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September 24, 2012

Industrial Customers Group
c/o Robert Hobbs
301-2298 McBain Avenue
Vancouver, BC V6L 3B1

Attention: Mr. Robert Hobbs

Dear Mr. Hobbs:

Re: Generic Cost of Capital Proceeding

FortisBC Utilities (the "FBCU")[1]

Response to Industrial Customers Group ("ICG") Information Request ("IR") No. 1 on the Evidence of Ms. Kathleen McShane

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On August 3, 2012, the FortisBC Utilities filed its Written Evidence in the Generic Cost of Capital proceeding as referenced above. In accordance with the British Columbia Utilities Commission Order No. G-84-12 setting out the Amended Preliminary Regulatory Timetable, the FBCU respectfully submit the attached response to ICG IR No. 1 on the Evidence of Ms. Kathleen McShane.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

on behalf of the FORTISBC UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Commission Secretary
Registered Parties

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[1] comprised of FortisBC Inc., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc.

1. Reference: **McShane, Testimony on the Cost of Capital for the Fortis BC Utilities,**

Rationale: **Ms. McShane states that "Satisfying the comparable return requirement of the fair return standard requires consideration of returns available to comparable utilities in the U.S., given the similarity of operating and regulatory environments."**

Request:

(a) Explain the basis for Ms. McShane's belief that the operating and regulatory environments for the U.S. and Canada are similar.

Response:

With respect to the operating environment, Ms. McShane's conclusion is based on the basic similarities of the economies, the technologies used to deliver gas and power, the manner in which the sectors are structured (e.g., franchises for service areas), demographic trends, industry trends (e.g., declining average customer usage in the gas distribution industry, capital requirements for aging infrastructure renewal, increasingly stringent environmental compliance regulations). With respect to the regulatory environment, please refer to the response to BCUC IR 1.54 series.

(b) Is Ms. McShane aware of any differences in the operating and regulatory environments? If so, please indicate what they are.

Response:

Each utility in each country is characterized by its own unique operating features, but Ms. McShane is not aware of any systematic differences between the operating environments in Canada and the U.S. With respect to the regulatory environment, please refer to the response to BCUC IR 1.54 series.

2. Reference: McShane, Testimony on the Cost of Capital for the Fortis BC Utilities,

Rationale: Ms. McShane includes several charts in her testimony: Chart 1 (p. 20). Chart 2 (p. 20), Chart 3 (p. 21), Chart 4 (p. 27), and Chart 5 (p. 51).

Request:

Please provide the data underlying the five charts in electronic format (Excel spreadsheet). If there are calculations involved in constructing the charts, please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The underlying data for Charts 3, 4, and 5 are provided in Attachment 2. For underlying data for Chart 1, please refer to the response to BCUC IR 1.36.1. The 30 year Government of Canada bond yield data supporting Chart 2 were provided in Attachment 36.2 in response to BCUC IR 1.36.2. As indicated in BCUC IR 1.36.2, the DEX data provided in Attachment 36.2 are proprietary and under strict-use license. Therefore, the data are being provided confidentially under separate cover to the Commission only for the purposes of this proceeding, and cannot be provided to other parties under the terms of the license.

3. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Appendix A, Chart A-1, A-2, p. 10.

Request:

Please provide the data underlying the referred to charts in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The underlying data for the two charts are provided in Attachment 3.

4. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 1.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 1 are provided in Attachment 4.

5. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 2.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 2 are provided in Attachment 5.

6. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 3.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 3, pages 1 and 2 of 2 are provided in Attachment 6. Please note that an incorrect capital structure is shown for Nova Scotia Power (NSPI) on Schedule 3, page 1 of 2. The correct NSPI capital structure for 2012 contains 58.8% debt, 3.60% preferred stock and 37.5% common equity.

7. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 4.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 4 are provided in Attachment 7.

8. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 5.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 5 are provided in Attachment 8.

9. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 6.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 6 are provided in Attachment 9.

10. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 7.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 7 are provided in Attachment 10.

11. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 8.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 8 are provided in Attachment 11.

12. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 9.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 9 are provided in Attachment 12.

13. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 10.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 10 are provided in Attachment 13.

14. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 11.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 11 are provided in Attachment 14.

15. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 12.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 12 are provided in Attachment 15.

16. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 13.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 13 are provided in Attachment 16.

17. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 14.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 14 are provided in Attachment 17.

(a) On p. 1 of Schedule 14, Ms. McShane provides raw betas based on monthly prices for selected Canadian regulated utilities. What type of monthly prices are used in the calculation? For example, are the monthly prices used in the beta calculation the prices for a specific day, such as the beginning or end of month price, or are they an average of the daily closing prices for the month? Please explain.

Response:

The raw monthly betas on Schedule 14, Page 1 of 6 are based on the monthly closing price.

(b) Similarly, on p. 3 Schedule 14, Ms. McShane provides raw betas based on weekly prices. As in 16(a) above, what type of weekly prices are used in the calculation? Please explain.

Response:

The raw weekly betas on Schedule 14, Page 3 of 6 are based on the closing price on Friday of each week.

18. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 17, page 1 of 2.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 17, page 1 of 2 are provided in Attachment 18.

19. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 17, page 2 of 2.

Request:

Please provide the data used to generate the three regressions referred to in the schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

Please refer to the response to ICG-McShane IR 1.18, Attachment 18, as all data used to generate the three regressions can be derived from Attachment 18.

20. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 18, schedules 2 and 3.

Request:

Please provide the data underlying the graphs contained in the referenced schedules in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data underlying the two graphs are provided in Attachment 20.

21. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 18, schedule 1.

Request:

Please provide the data used to generate the averages and returns given in the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data used to generate the averages and returns in Schedule 18, page 1 are provided in Attachment 21.

22. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 19.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 19 are provided in Attachment 22.

23. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 20.

Request:

(a) Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 20 are provided in Attachment 23a.

(b) Please provide the source documents for the data given in columns (4) ("Forecast Return on Common Equity") and (5) (Forecast Earnings Retention Rate).

Response:

The source documents for columns (4) and (5) are provided in Attachment 23b.

(c) Please provide the source data used to derive the entries for column (7) in electronic format (Excel spreadsheet). Please include within the spreadsheet any formulas used to make the calculations.

Response:

The source data used to derive the entries for column 7 are provided in Attachment 23c.

24. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 21.

Request:

(a) Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 21 are provided in Attachment 24a.

(b) Please provide the underlying source documents for the data presented in Schedule 21.

<u>Response:</u>

Price and dividend data are publicly available from www.yahoo.com. The source documents for the Bloomberg, Reuters and Zacks Earnings forecasts and the GDP growth forecast are provided in Attachment 24b. The Value Line forecasts were provided in Attachment 23b in response to ICG-McShane IR 1.23b.

25. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 22.

Request:

(a) Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

<u>Response:</u>

The data in Schedule 22 are provided in Attachment 25a.

(b) Please provide the underlying source documents for the data presented in Schedule 22.

<u>Response:</u>

Price and dividend data are publicly available from www.yahoo.com. Reuters Long-Term EPS forecasts are provided in Attachment 25b.

26. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 23.

Request:

(a) Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 23 are provided in Attachment 26a.

(b) Please provide the underlying source documents for the data presented in Schedule 23.

Response:

Price and dividend data are publicly available from www.yahoo.com. Reuters Long-Term EPS forecasts were provided in Attachment 25b in response to ICG-McShane IR 1.25b. The source document for GDP Growth is provided in Attachment 26b.

27. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 24.

Request:

(a) Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 24 are provided in Attachment 27a.

(b) Please provide the underlying source documents for the data presented in Schedule 24.

Response:

All data were downloaded directly from www.dbrs.com or from the proprietary Standard & Poor's Research Insight electronic database.

28. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 25.

Request:

(a) Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 25 are provided in Attachment 28a.

(b) Please provide the underlying source data for the calculations made to derive the data presented in Schedule 25.

Response:

The data presented on Schedule 25 are a direct download from the proprietary Standard & Poor's Research Insight electronic database. There are no source documents.

29. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 26.

Request:

(a) Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

The data in Schedule 26 are provided in Attachment 29a.

(b) Please provide the underlying source documents for the data presented in Schedule 26.

Response:

The underlying source documents for the data in Columns 1 and 3 are provided in Attachment 29b. The market prices are publicly available at www.yahoo.com.

30. Reference: McShane, Testimony on the Cost of Capital for the FortisBC Utilities, Schedule 1.

Request:

Please provide the data comprising the referred to schedule in electronic format (Excel spreadsheet). Please provide the spreadsheet in such a format that any formulas used to derive any of the calculations are preserved.

Response:

Please refer to the response to ICG-McShane IR 1.4.

Attachment 2

REFER TO LIVE SPREADSHEET

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 3

REFER TO LIVE SPREADSHEET

Provided in electronic format only

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Attachment 4

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Attachment 5

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Attachment 6

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Attachment 7

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Attachment 8

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Attachment 9

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Attachment 10

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Attachment 11

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Attachment 12

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Attachment 13

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Attachment 14

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Attachment 15

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Attachment 16

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Attachment 17

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Attachment 18

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Attachment 20

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Attachment 21

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Attachment 22

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Attachment 23a

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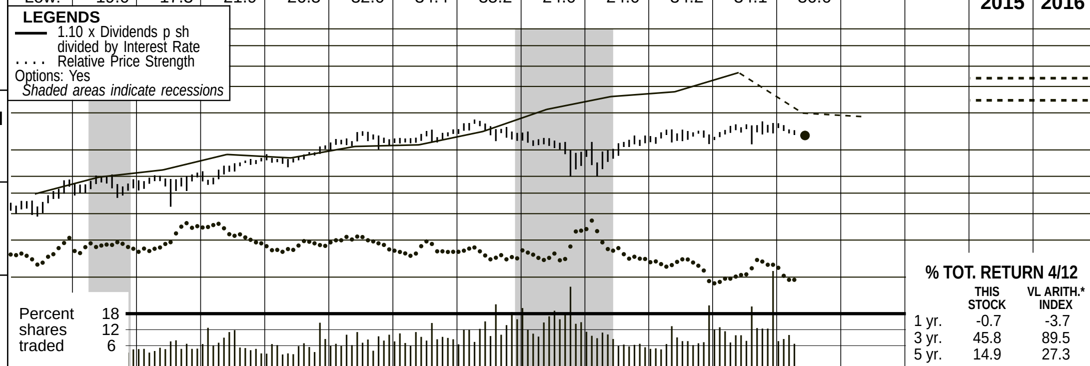
Attachment 23b

AGL RESOURCES NYSE-GAS

RECENT PRICE	37.54	P/E RATIO	13.4 (Trailing: 21.8, Median: 13.0)	RELATIVE P/E RATIO	0.93	DIV'D YLD	4.9%	VALUE LINE

TIMELINESS 3 Raised 3/11/11
SAFETY 1 Raised 9/9/11
TECHNICAL 3 Raised 5/18/12
BETA .75 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9
Low:	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6



Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+85%)	17%
Low	55	(+45%)	10%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	1	1	0	1	1	0
to Sell	0	0	0	1	2	0	0	1	0

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	109	99	258
to Sell	104	118	63
Hld's(000)	50316	50506	71384

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.7	-3.7
3 yr.	45.8	89.5
5 yr.	14.9	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	20.00	*40.25*	*42.00*	Revenues per sh A	*47.50*
2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.05	*6.55*	*6.85*	"Cash Flow" per sh	*7.75*
1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	*2.80*	*3.10*	Earnings per sh A B	*4.10*
1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	2.26	*1.74*	*1.84*	Div'ds Decl'd per sh C■	*2.00*
2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.42	*5.75*	*5.90*	Cap'l Spending per sh	*6.30*
10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	28.54	*30.05*	*31.85*	Book Value per sh D	*36.35*
55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.00	*118.00*	*119.00*	Common Shs Outst'g E	*121.00*
13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	.82	*Value Line*		Relative P/E Ratio	*1.00*
5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	*4750*	*5000*	Revenues ($mill) A	*5750*
103.0	132.4	153.0	193.0	212.0	211.0	207.6	222.0	234.0	172.0	*330*	*370*	Net Profit ($mill)	*495*
36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	*7.0%*	*7.4%*	Net Profit Margin	*8.6%*
58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	52.0%	*50.0%*	*48.0%*	Long-Term Debt Ratio	*43.0%*
41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	48.0%	*50.0%*	*52.0%*	Common Equity Ratio	*57.0%*
1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	8238.0	*7015*	*7075*	Total Capital ($mill)	*7260*
2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	*8035*	*8175*	Net Plant ($mill)	*8470*
8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	3.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.5%*
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*9.5%*	*10.0%*	Return on Shr. Equity	*12.0%*
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*9.5%*	*10.0%*	Return on Com Equity	*12.0%*
7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	.7%	*4.5%*	*4.0%*	Retained to Com Eq	*6.0%*
52%	53%	49%	52%	52%	58%	60%	57%	57%	86%	*49%*	*62%*	All Div'ds to Net Prof	*49%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $4288.0 mill. **Due in 5 Yrs** $950.0 mill.
LT Debt $3558.0 mill. **LT Interest** $190.0 mill.
(Total interest coverage: 6.5x)

Leases, Uncapitalized Annual rentals $95.0 mill.
Pension Assets-12/11 $754.0 mill.
Oblig. $968.0 mill.

Pfd Stock None

Common Stock 117,310,372 shs.
as of 4/26/12

MARKET CAP: $4.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	24.0	69.0	71.0
Other	2138.0	2677.0	1951.0
Current Assets	2162.0	2746.0	2022.0
Accts Payable	184.0	294.0	205.0
Debt Due	1032.0	1338.0	730.0
Other	1212.0	1452.0	1413.0
Current Liab.	2428.0	3984.0	2348.0
Fix. Chg. Cov.	501%	325%	465%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	5.5%	*-2.5%*
"Cash Flow"	6.5%	6.0%	*2.5%*
Earnings	9.0%	4.5%	*5.5%*
Dividends	5.0%	7.5%	*2.0%*
Book Value	7.0%	5.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	995.0	377.0	307.0	638.0	2317.0
2010	1003	359.0	346.0	665.0	2373.0
2011	878.0	375.0	295.0	790.0	2338.0
2012	1404	*700*	*1000*	*1646*	*4750*
2013	*1600*	*800*	*1000*	*1600*	*5000*

Cal-endar	EARNINGS PER SHARE AB Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.55	.26	.16	.91	2.88
2010	1.73	.17	.29	.81	3.00
2011	1.59	.23	d.04	.37	2.12
2012	1.16	*.35*	*.45*	*.84*	*2.80*
2013	*1.50*	*.35*	*.50*	*.75*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.42	.42	.42	.42	1.68
2009	.43	.43	.43	.43	1.72
2010	.44	.44	.44	.44	1.76
2011	.45	.45	.45	.55	2.26
2012	.36	.46			

BUSINESS: AGL Resources Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, and Virginia Natural Gas. The utilities have more than 2.3 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. BlackRock Inc. owns 6.8% of common stock; off./dir., less than 1.0% (3/12 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

The newly merged AGL Resources had a lackluster first quarter. Per-share earnings fell to $1.16, a 27% drop from the March, 2011 period. Warmer-than-expected weather was the main reason for the decline. Thus, we have lowered our full-year estimate by $0.45, to $2.80.

Several obstacles could hinder growth for the next few years. Concerns include subpar customer growth, owing to the slow recovery in the housing market, and a lack of new rate case filings. We also remain concerned about low natural gas storage demand (storage inventories are reaching record highs due to a supply glut), which could impact contracted rates and terms at the company's midstream segment. In turn, both factors could provide headwinds for both the top and bottom lines.

New contracts might ease some of the upcoming pressure. Despite the lower storage demand (above), Sequent Energy Management's brand strength has netted it several new storage contracts, along with various renewed contracts. Management hopes to lock in additional contracts as the year goes on, and these should work to partly offset some of the stress on revenues and earnings, though their full impact is uncertain at this point.

The long term offers some promise, although there are also some uncertanties. As a result of favorable rate rulings over the past few years, AGL Resources is expecting a considerable boost to revenues going forward. Furthermore, its merger with Nicor makes it the largest natural gas distributor in the country, with a particularly strong position in the Midwest. Thus, a rise in volumes via core growth could result in a strong profit showing. However, we remain concerned that increasing competition at the retail level in Georgia could hold back the bottom line, and thus hurt the 2015-2017 period performace. Sideline businesses could be hurt by low gas prices too.

This neutrally ranked equity has below-average appreciation potential, but income investors will find it most appealing. With its normalized quaterly payouts now at $0.46 a share, the stock offers an above-industry average dividend yield, and strong possibility of future payout hikes.

Sahana Zutshi *June 8, 2012*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses):'99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late July.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2011: $1918 million, $16.40/share.
(E) In millions.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	90

ALLIANT ENERGY NYSE-LNT

RECENT PRICE **45.10** | P/E RATIO **16.1** (Trailing: 17.5 / Median: 14.0) | RELATIVE P/E RATIO **1.13** | DIV'D YLD **4.1%** | **VALUE LINE**

TIMELINESS	3	Lowered 2/25/11	
SAFETY	2	Raised 9/28/07	
TECHNICAL	3	Raised 5/11/12	
BETA .75 (1.00 = Market)			

High:	33.2	31.0	25.1	28.8	30.6	40.0	46.5	42.4	31.5	37.7	44.5	45.7
Low:	27.5	14.3	15.0	23.5	25.6	27.5	34.9	22.8	20.3	29.2	33.9	41.9

Target Price Range

2015	2016	2017

2015-17 PROJECTIONS

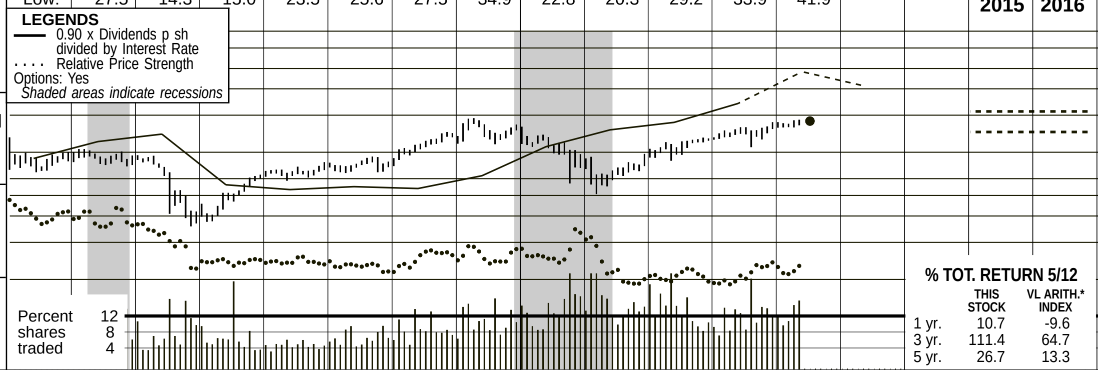
	Price	Gain	Ann'l Total Return
High	50	(+10%)	7%
Low	40	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	1	0	0	0	1	0	0	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	134	150	129
to Sell	120	127	147
Hld's(000)	63051	60603	61552



% TOT. RETURN 5/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.7	-9.6
3 yr.	111.4	64.7
5 yr.	26.7	13.3

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
28.26	28.19	25.56	28.02	28.93	31.15	33.33	31.02	30.81	33.02	***29.45***	***30.95***	Revenues per sh	***38.80***
4.52	4.19	4.69	5.46	4.33	5.12	4.56	4.21	5.21	5.65	***5.85***	***6.20***	"Cash Flow" per sh	***7.05***
1.18	1.57	1.85	2.21	2.06	2.69	2.54	1.89	2.75	2.75	***2.80***	***3.00***	Earnings per sh A	***3.50***
2.00	1.00	1.02	1.05	1.15	1.27	1.40	1.50	1.58	1.70	***1.80***	***1.90***	Div'd Decl'd per sh B ■ †	***2.20***
7.12	7.69	5.55	4.51	3.42	4.91	7.96	10.87	7.82	6.22	***5.35***	***7.10***	Cap'l Spending per sh	***9.50***
19.89	21.37	22.13	20.85	22.83	24.30	25.56	25.07	26.09	27.14	***29.45***	***30.55***	Book Value per sh C	***32.35***
92.30	110.96	115.74	117.04	116.13	110.36	110.45	110.66	110.89	111.02	***112.00***	***113.00***	Common Shs Outst'g D	***116.00***
19.9	12.7	14.0	12.6	16.8	15.1	13.4	13.9	12.5	14.5	*Bold figures are*		Avg Ann'l P/E Ratio	***13.0***
1.09	.72	.74	.67	.91	.80	.81	.93	.80	.92	*Value Line*		Relative P/E Ratio	***.85***
8.5%	5.0%	3.9%	3.8%	3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	*estimates*		Avg Ann'l Div'd Yield	***4.8%***
2608.8	3128.2	2958.7	3279.6	3359.4	3437.6	3681.7	3432.8	3416.1	3665.3	***3300***	***3500***	Revenues ($mill)	***4500***
113.1	176.6	229.5	337.8	260.1	320.8	280.0	208.6	303.9	304.4	***315***	***340***	Net Profit ($mill)	***400***
24.2%	28.9%	26.7%	19.0%	43.8%	44.4%	33.4%	- -	30.1%	14.7%	***30.0%***	***30.0%***	Income Tax Rate	***30.0%***
6.8%	11.7%	8.1%	3.0%	3.1%	2.4%	- -	- -	8.8%	6.0%	***6.0%***	***6.0%***	AFUDC % to Net Profit	***6.0%***
56.4%	44.8%	45.0%	41.6%	31.4%	32.4%	36.3%	44.3%	46.3%	45.7%	***46.0%***	***46.0%***	Long-Term Debt Ratio	***47.0%***
39.2%	50.0%	50.2%	53.1%	62.9%	61.9%	58.6%	51.2%	49.5%	50.9%	***50.5%***	***51.0%***	Common Equity Ratio	***50.5%***
4679.1	4738.4	5104.7	4599.1	4218.4	4329.5	4815.6	5423.0	5840.8	5921.2	***6505***	***6755***	Total Capital ($mill)	***7455***
3729.2	4432.6	5284.6	4866.2	4944.9	4679.9	5353.5	6203.0	6730.6	7037.1	***7200***	***7500***	Net Plant ($mill)	***8200***
4.1%	5.7%	6.1%	8.9%	7.5%	8.6%	7.0%	5.1%	6.6%	6.7%	***6.0%***	***6.5%***	Return on Total Cap'l	***7.0%***
5.5%	6.8%	8.2%	12.6%	9.0%	11.0%	9.1%	6.9%	9.7%	9.5%	***9.0%***	***9.5%***	Return on Shr. Equity	***10.0%***
5.8%	6.7%	8.2%	13.1%	9.1%	11.3%	9.3%	6.8%	9.9%	10.1%	***9.5%***	***10.0%***	Return on Com Equity E	***10.5%***
NMF	2.5%	3.8%	8.1%	4.0%	5.9%	3.8%	.9%	3.8%	3.4%	***3.0%***	***3.0%***	Retained to Com Eq	***3.5%***
NMF	67%	58%	42%	59%	50%	62%	88%	64%	66%	***68%***	***67%***	All Div'ds to Net Prof	***67%***

CAPITAL STRUCTURE as of 3/31/12
Total Debt $2786.6 mill. **Due in 5 Yrs** $543.4 mill.
LT Debt $2728.2 mill. **LT Interest** $155.0 mill.
(LT interest earned: 2.4x)

Pension Assets-12/11 $1081.4 mill. **Oblig.** $897.4 mill.
Pfd Stock $205.1 mill. **Pfd Div'd** $16.0 mill.
449,765 shs. $100 par; 6,599,460 shs. $25 par

Common Stock 110,962,089 shs.

MARKET CAP: $5.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-6.8	+2.8	+.9
Avg. Indust. Use (MWH)	10948	11213	11054
Avg. Indust. Revs. per KWH (¢)	6.33	6.80	6.51
Capacity at Peak (Mw)	5491	5425	5734
Peak Load, Summer (Mw)	5491	5425	5734
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.1	+.2	+.2
Fixed Charge Cov. (%)	256	306	237

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.0%	3.0%	*3.5%*
"Cash Flow"	-2.0%	-.5%	*6.0%*
Earnings	2.0%	5.0%	*6.0%*
Dividends	-3.0%	8.0%	*5.5%*
Book Value	.5%	3.5%	*3.5%*

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	949.9	742.3	885.7	854.9	3432.8
2010	890.2	741.6	951.7	832.6	3416.1
2011	945.0	819.5	1021.6	879.2	3665.3
2012	765.7	***720***	***1050***	***764.3***	***3300***
2013	***800***	***760***	***1160***	***780***	***3500***

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.30	.34	.77	.48	1.89
2010	.45	.44	1.31	.55	2.75
2011	.68	.44	1.12	.51	2.75
2012	.50	***.45***	***1.25***	***.60***	***2.80***
2013	***.55***	***.50***	***1.30***	***.65***	***3.00***

QUARTERLY DIVIDENDS PAID B ■†

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.35	.35	.35	.35	1.40
2009	.375	.375	.375	.375	1.50
2010	.395	.395	.395	.395	1.58
2011	.425	.425	.425	.425	1.70
2012	.45	.45			

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 47%; IA, 50%; MN, 3%. Elect. rev.: residential, 37%; commercial, 23%; industrial, 28%; wholesale, 7%; other, 5%. Fuel sources, 2011: coal, 52%; nuclear, 17%; gas, 2%; other, 29%. Fuel costs: 45% of revs. 2011 depreciation rate: 4.6%. Estimated plant age: 10 years. Has 4,262 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy posted unimpressive results for the first quarter. The utility operations were hurt by unusually warm weather, which led to lower electric and natural gas sales to residential and commercial customers. This was partly offset by greater electric sales to industrial customers. Looking forward,

We have pared our bottom-line estimate by a dime for the current year. We expect share net to come in near the lower end of Alliant's guidance of $2.75-$3.05 for 2012. We look for decent results from the utilities going forward, assuming a stable economy and normal weather for the remainder of the year. The planned sale of RMT, a renewable energy service provider, should allow Alliant to increase focus on its core operations.

The company has been active on the regulatory front. Interstate Power and Light has filed a request with the Iowa Utilities Board seeking recovery of natural gas system improvements. Specifically, IPL is asking to increase its Iowa annual retail rates by about $14.8 million (5.6%). A final ruling is expected on or before April, 2013. In the meantime, interim rates ought to increase natural gas revenues by $8.6 million (3.3%), on an annual basis. Elsewhere, Wisconsin Power and Light has requested a $25 million (2.5%) decrease in retail rates for 2013, due to expected lower electric fuel costs. The company will probably receive approval for the 2013 annual electric fuel cost plan by the end of the current year. WPL is also seeking a decline in annual retail gas rates by $13 million (7%) for next year, and to freeze rates for 2014.

This issue is neutrally ranked for year-ahead performance. Looking further out, we anticipate higher revenues and share earnings for the company by 2015-2017. Moreover, Alliant earns favorable marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. From the recent quotation, this equity has unimpressive, though relatively well-defined, total return potential for the coming years. The stock's healthy dividend yield might appeal to income-seeking accounts. However, investors focused on capital appreciation can probably find better choices elsewhere.

Michael Napoli, CFA *June 22, 2012*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '01, (28¢); '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 83¢; '07, $1.09; '08, 7¢; '09, (88¢); '10, (15¢); '11, (1¢). Next egs. rpt. due in August.
(B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † shareholder invest. plan avail. (C) Incl. deferred chgs. in '11: $92.1 mill., $0.83/sh. (D) In mill.
(E) Rate base: Orig. cost. Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	70

ATMOS ENERGY CORP. NYSE-ATO

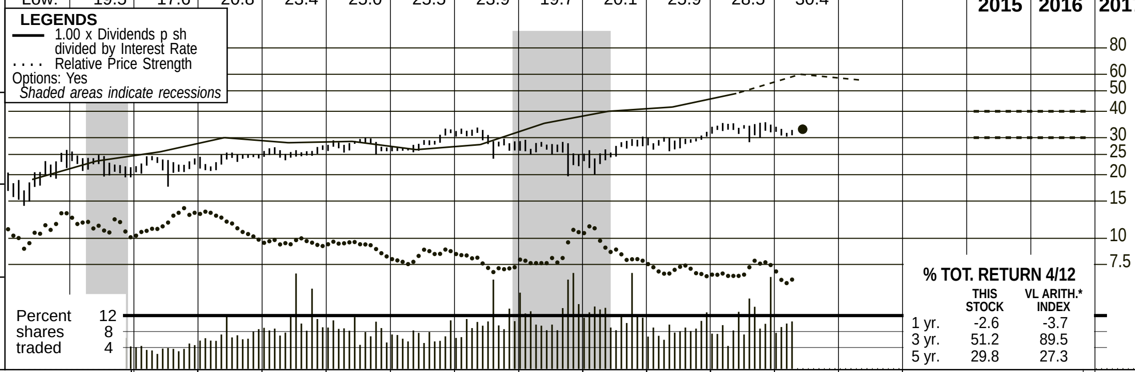
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
32.90	15.7	(Trailing: 17.0 Median: 14.0)	1.09	4.3%	VALUE LINE

TIMELINESS 3 Raised 3/30/12
SAFETY 2 Raised 12/16/05
TECHNICAL 4 Lowered 5/25/12
BETA .70 (1.00 = Market)

High:	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.6	33.9
Low:	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4

Target Price Range
2015 | 2016 | 2017

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	9%
Low	30	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	2	0	0	0	1

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	112	110	132
to Sell	105	116	103
Hld's(000)	50093	50338	48646

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.6	-3.7
3 yr.	51.2	89.5
5 yr.	29.8	27.3

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.82	54.39	46.50	61.75	75.27	66.03	79.52	53.69	53.12	48.15	*44.55*	*49.00*	Revenues per sh A	*63.10*
3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.29	4.64	4.72	*4.65*	*5.05*	"Cash Flow" per sh	*5.65*
1.45	1.71	1.58	1.72	2.00	1.94	2.00	1.97	2.16	2.26	*2.00*	*2.30*	Earnings per sh A B	*2.70*
1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	1.36	*1.38*	*1.40*	Div'ds Decl'd per sh C■	*1.48*
3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.51	6.02	6.90	*7.75*	*7.95*	Cap'l Spending per sh	*8.80*
13.75	16.66	18.05	19.90	20.16	22.01	22.60	23.52	24.16	24.98	*28.75*	*30.00*	Book Value per sh	*34.65*
41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.55	90.16	90.30	*90.00*	*91.00*	Common Shs Outst'g D	*103.00*
15.2	13.4	15.9	16.1	13.5	15.9	13.6	12.5	13.2	14.4	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.83	.76	.84	.86	.73	.84	.82	.83	.84	.90	*Value Line*		Relative P/E Ratio	*.85*
5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*
950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	*4010*	*4460*	Revenues ($mill) A	*6500*
59.7	79.5	86.2	135.8	162.3	170.5	180.3	179.7	201.2	199.3	*180*	*210*	Net Profit ($mill)	*280*
37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	*38.5%*	*38.5%*	Income Tax Rate	*38.5%*
6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	*4.5%*	*4.7%*	Net Profit Margin	*4.3%*
53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	*46.5%*	*48.5%*	Long-Term Debt Ratio	*49.0%*
46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	*53.5%*	*51.5%*	Common Equity Ratio	*51.0%*
1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	*4840*	*5300*	Total Capital ($mill)	*7000*
1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	*5500*	*5800*	Net Plant ($mill)	*6700*
6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	*7.0%*	*7.5%*	Return on Shr. Equity	*8.0%*
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	*7.0%*	*7.5%*	Return on Com Equity	*8.0%*
1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	*2.0%*	*3.0%*	Retained to Com Eq	*3.5%*
82%	70%	77%	73%	63%	65%	65%	68%	62%	62%	*69%*	*61%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $2380.3 mill. **Due in 5 Yrs** $660.0 mill.
LT Debt $1956.2 mill. **LT Interest** $110.0 mill.
(LT interest earned: 3.1x; total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $17.7 mill.
Pfd Stock None
Pension Assets-9/11 $280.2 mill. **Oblig.** $429.4 mill.
Common Stock 90,030,471 shs. as of 4/27/12
MARKET CAP: $3.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	132.0	131.4	47.0
Other	743.2	879.6	846.8
Current Assets	875.2	1011.0	893.8
Accts Payable	266.2	291.2	309.9
Debt Due	486.2	208.8	424.1
Other	413.7	367.6	374.1
Current Liab.	1166.1	867.6	1108.1
Fix. Chg. Cov.	440%	432%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.5%	-3.5%	*3.5%*
"Cash Flow"	4.5%	4.5%	*3.5%*
Earnings	7.0%	4.0%	*4.0%*
Dividends	1.5%	1.5%	*1.5%*
Book Value	6.5%	4.5%	*6.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1716.3	1821.4	780.8	650.6	4969.1
2010	1292.9	1940.3	770.2	786.3	4789.7
2011	1133.3	1581.5	843.6	789.2	4347.6
2012	1101.2	1243.4	*870*	*795.4*	*4010*
2013	*1205*	*1600*	*850*	*805*	*4460*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.83	1.29	.02	d.17	1.97
2010	1.00	1.17	d.03	.02	2.16
2011	.81	1.40	.04	.01	2.26
2012	.72	1.16	*.09*	*.03*	*2.00*
2013	*.82*	*1.38*	*.07*	*.03*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.325	.325	.325	.33	1.31
2009	.33	.33	.33	.335	1.33
2010	.335	.335	.335	.34	1.35
2011	.34	.34	.34	.345	1.37
2012	.345	.345			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2011 gas volumes: 281.5 MMcf. Breakdown: 57%, residential; 32%, commercial; 7%, industrial; and 4% other. 2011 depreciation rate 3.3%. Has around 4,750 employees. Officers and directors own 1.5% of common stock (12/11 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy Corporation's core natural gas distribution unit registered a drop in profits during the first half of fiscal 2012. (Years end on September 30th.) That was attributed partly to a 10% decline in throughput, as warmer weather constrained consumption. Furthermore, revenue-related taxes were lower, due to decreased revenues on which the tax is calculated. But the segment benefited from rate hikes, especially in the Texas, Louisiana, Mississippi, and Kentucky service areas.

The other businesses had mixed performances. The nonregulated division suffered from unfavorable pricing conditions in the natural gas market, arising from a combination of abundant supply and diminished demand. Meanwhile, results for the regulated transmission and storage segment were aided by rate design adjustments approved in the Atmos Pipeline—Texas case that became effective in May, 2011.

It appears that consolidated share net will fall more than 10%, to $2.00, this fiscal year. Still, assuming that units presently struggling perk up, the bottom line stands to bounce back to $2.30 a share in fiscal 2013.

There are plans to sell the natural gas distribution operations in Missouri, Iowa, and Illinois (serving around 84,000 customers) to an affiliate of Algonquin Power & Utilities Corp. The estimated $124 million in proceeds would be used to support growth initiatives in such key states as Texas and Louisiana. Pending regulatory approvals, the transaction is expected to close sometime during fiscal 2012. Please note that our presentation accounts for those businesses as discontinued.

The stock's dividend yield ranks favorably compared to that of other gas utility equities covered by *Value Line*. Our 3- to 5-year projections indicate that additional, although moderate, increases in the distribution are likely to occur. The payout ratio ought to remain within a manageable range (i.e., 55% to 60%). What's more, these shares hold a 2 (Above Average) Safety rating and an excellent score for Price Stability. But the Timeliness rank is only 3 (Average).

Frederick L. Harris, III *June 8, 2012*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '03, d17¢; '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 6¢. Next egs. rpt. due early Aug. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	90

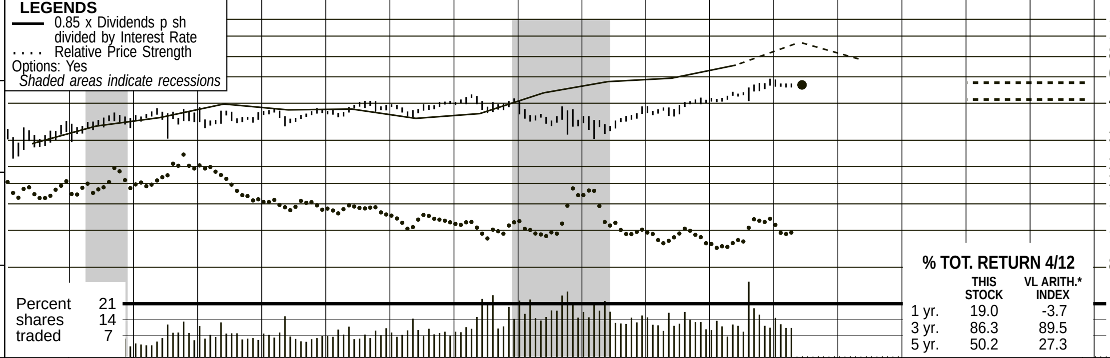
CON. EDISON NYSE-ED

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
58.75	15.9	(Trailing: 16.7 Median: 14.0)	1.10	4.1%	VALUE LINE

TIMELINESS 3 Raised 8/20/10
SAFETY 1 New 7/27/90
TECHNICAL 3 Raised 5/18/12
BETA .60 (1.00 = Market)

													Target Price Range
High:	43.4	45.4	46.0	45.6	49.3	49.3	52.9	49.3	46.3	51.0	62.7	62.3	2015 | 2016 | 2017
Low:	31.4	32.7	36.6	37.2	41.1	41.2	43.1	34.1	32.6	41.5	48.6	57.0	

LEGENDS
— 0.85 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(Nil)	*5%*
Low	50	(-15%)	*1%*

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	1	0	0	1	0	0	1	0	0
Options	0	0	0	0	0	3	1	0	0
to Sell	0	0	1	0	0	3	2	1	0

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	254	311	300
to Sell	198	189	213
Hld's(000)	127233	122506	125157

Percent shares traded 21 14 7

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.0	-3.7
3 yr.	86.3	89.5
5 yr.	50.2	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
29.62	30.24	30.46	35.04	44.48	45.41	39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	*43.70*	*45.05*	Revenues per sh	*50.25*
4.97	5.08	5.29	5.74	5.51	5.70	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	*6.95*	*7.30*	"Cash Flow" per sh	*8.50*
2.93	2.95	3.04	3.13	2.74	3.21	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	*3.70*	*3.85*	Earnings per sh A	*4.25*
2.08	2.10	2.12	2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	*2.42*	*2.44*	Div'd Decl'd per sh B ■	*2.50*
2.87	2.78	2.66	3.17	4.52	5.20	5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	*7.55*	*7.30*	Cap'l Spending per sh	*7.25*
24.37	25.18	25.88	25.31	25.81	26.71	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	*40.35*	*41.80*	Book Value per sh C	*47.00*
234.99	235.49	232.83	213.81	212.03	212.15	213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	*293.00*	*293.00*	Common Shs Outst'g D	*293.00*
10.1	10.9	15.3	14.0	12.0	12.0	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.63	.63	.80	.80	.78	.61	.73	.82	.96	.80	.84	.73	.74	.83	.85	.96	*Value Line*		Relative P/E Ratio	*.85*
7.0%	6.5%	4.6%	4.9%	6.6%	5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 12/31/11
Total Debt $10675 mill. **Due in 5 Yrs** $2942.0 mill.
LT Debt $10145 mill. **LT Interest** $507.0 mill.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $50.0 mill.
Pension Assets-12/11 $7.80 bill. **Oblig.** $11.8 bill.
Pfd Stock $213.0 mill. **Pfd Div'd** $11.0 mill.
1,915,319 shs. $5 cum. no par, call. $105 a sh.; 375,626 shs. 4.65% cum. $100 par, call. $101 to $102.50 a sh.
Common Stock 292,880,631 shs.
as of 1/31/12
MARKET CAP: $17 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
8482.0	9827.0	9758.0	11690	12137	13120	13583	13032	13325	12938	*12800*	*13200*	Revenues ($mill)	*14700*
682.1	639.0	560.0	719.0	749.0	936.0	933.0	868.0	992.0	1062.0	*1095*	*1140*	Net Profit ($mill)	*1290*
36.9%	33.7%	34.3%	33.6%	35.2%	32.6%	36.0%	34.2%	36.0%	36.1%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
2.2%	4.2%	7.7%	2.2%	1.6%	1.9%	1.7%	2.6%	2.4%	1.6%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
50.1%	50.4%	47.4%	49.6%	50.2%	45.6%	48.3%	48.5%	48.6%	46.5%	*46.5%*	*46.0%*	Long-Term Debt Ratio	*45.5%*
48.1%	48.0%	51.0%	49.0%	48.5%	53.1%	50.6%	50.4%	50.4%	52.5%	*53.5%*	*54.0%*	Common Equity Ratio	*54.5%*
12302	13369	13828	14921	16515	16687	19160	20330	21952	21794	*22000*	*22700*	Total Capital ($mill)	*25200*
13329	15225	16106	17112	18445	19914	20874	22464	23863	25093	*26350*	*27500*	Net Plant ($mill)	*30200*
7.1%	6.3%	5.6%	6.3%	6.0%	7.0%	6.2%	5.7%	5.9%	6.2%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
11.1%	9.6%	7.7%	9.6%	9.1%	10.3%	9.4%	8.3%	8.8%	9.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
11.3%	9.8%	7.8%	9.7%	9.2%	10.4%	9.5%	8.4%	8.9%	9.2%	*9.0%*	*9.5%*	Return on Com Equity E	*9.5%*
4.0%	2.9%	.8%	2.6%	2.6%	3.9%	3.1%	2.5%	3.2%	3.1%	*3.0%*	*3.5%*	Retained to Com Eq	*4.0%*
65%	71%	89%	74%	73%	63%	67%	71%	65%	66%	*65%*	*63%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-.9	+3.6	-1.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	12242	12963	NA
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	296	331	360

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.0%	- -	*1.5%*
"Cash Flow"	1.0%	4.5%	*5.5%*
Earnings	1.0%	4.5%	*4.0%*
Dividends	1.0%	1.0%	*1.0%*
Book Value	4.0%	4.5%	*8.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3423	2845	3489	3275	13032
2010	3462	3017	3707	3139	13325
2011	3349	2993	3629	2967	12938
2012	3078	*3022*	*3700*	*3000*	*12800*
2013	*3200*	*3100*	*3800*	*3100*	*13200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.66	.55	1.20	.73	3.14
2010	.80	.64	1.23	.80	3.47
2011	1.06	.56	1.30	.65	3.57
2012	.94	*.65*	*1.35*	*.76*	*3.70*
2013	*1.05*	*.65*	*1.35*	*.80*	*3.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.585	.585	.585	.585	2.34
2009	.59	.59	.59	.59	2.36
2010	.595	.595	.595	.595	2.38
2011	.60	.60	.60	.60	2.40
2012	.605				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R, acquired 7/99), which operates in New York, New Jersey, and Pennsylvania. Has 3.6 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Purchases most of its power. Fuel costs: 39% of revenues. '11 reported depreciation rates: 2.8%-3.1%. Has 15,000 employees. Chairman, President & CEO: Kevin Burke. Inc.: New York. Address: 4 Irving Place, New York, NY 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

We estimate that Consolidated Edison's earnings will increase this year and next. The utility is benefiting from the economic recovery and from customers' conversions from heating oil to natural gas. As prices of the former have risen, prices for the latter have fallen. Our 2012 earnings estimate, which we have trimmed by a nickel a share, is still within management's targeted range of $3.65-$3.85. Note that our presentation *includes* mark-to-market accounting gains or losses stemming from ConEd's competitive energy operations.

ConEd Company of New York's regulatory plan expires at the end of March, 2013. The utility is still deciding whether to seek an extension of the current plan or file another one. For the 12 months that ended on March 31st, CECONY earned slightly below its allowed return on equity for electricity and gas, but well below its allowed ROE for steam. Our 2013 earnings forecast is based on no change in rates at CECONY.

Orange and Rockland has an electric rate case pending in New York. The utility has made two alternative proposals for the next three years, beginning in mid-2012: either rate hikes of $19.4 million, $8.8 million, and $15.2 million, or increases of $15.2 million each year. The allowed ROE would be 9.4% in the first year, followed by 9.5% and 9.6% in the following two years, respectively. The common-equity ratio would be 48%. A ruling from the New York State commission is due next month. Our figures assume reasonable regulatory treatment.

The competitive energy businesses have had an inconsistent performance in recent years. Their $0.11-a-share profit in 2011 was the lowest since 2005. Even so, they are earning an ROE that exceeds the returns provided by the regulated utility operations.

This top-quality stock has a dividend yield that is average, by utility standards. Dividend growth has been steady but slow, and we project a continuation of 1% annual increases through 2015-2017. With the quotation near the upper end of our 3- to 5-year Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *May 25, 2012*

(A) Diluted EPS. Excl. nonrecurring losses: '02, 11¢; '03, 45¢; gain on discontinued operations: '08, $1.01. Next earnings report due late July. (B) Dividends historically paid in mid-Mar., mid-June, mid-Sept., and mid-Dec. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '10: $1.48/sh. (D) In millions. (E) Rate base: net original cost. Rate allowed on com. eq. for CECONY in '10: 10.15% electric, 9.6% gas and steam; O&R in '10 (electric) 9.2%, in '09 (gas) 10.3%; earned on avg. com. eq., '11: 9.5%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	85

INTEGRYS ENERGY NYSE-TEG

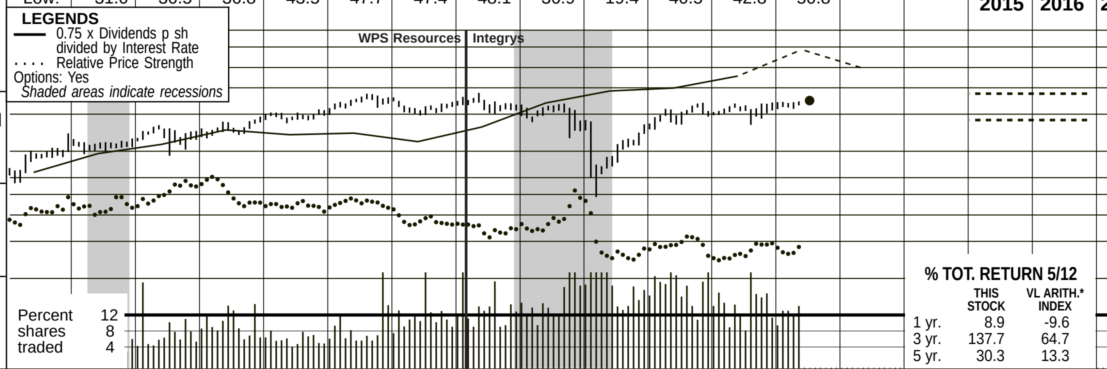
RECENT PRICE **55.77** | P/E RATIO **18.3** (Trailing: 19.4 / Median: 15.0) | RELATIVE P/E RATIO **1.28** | DIV'D YLD **4.9%** | **VALUE LINE**

TIMELINESS 3 New 3/26/10
SAFETY 2 Raised 6/24/11
TECHNICAL 3 Raised 5/18/12
BETA .90 (1.00 = Market)

High:	36.8	42.7	46.8	50.5	60.0	57.8	60.6	53.9	45.1	54.4	54.6	56.2
Low:	31.0	30.5	36.8	43.5	47.7	47.4	48.1	36.9	19.4	40.5	42.8	50.8

Target Price Range
2015 | 2016 | 2017

LEGENDS
—— 0.75 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	6%
Low	45	(-20%)	Nil

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	2	0	12	6
to Sell	0	0	0	1	1	2	0	2	10

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	127	132	125
to Sell	137	134	147
Hld's(000)	38990	38784	42436

% TOT. RETURN 5/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.9	-9.6
3 yr.	137.7	64.7
5 yr.	30.3	13.3

Integrys Energy Group was created as a holding company on February 21, 2007 to oversee the entire operations of the recently merged WPS Resources and Peoples Energy. WPS acquired Peoples in an agreement under which each common share of Peoples was converted into .825 share of WPS common. The combination took the new name of Integrys Energy Group. All data on this page prior to 2/21/07 are for WPS Resources only.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
83.55	117.07	131.26	173.37	160.01	135.44	184.86	98.71	67.27	60.44	*57.10*	*62.90*	Revenues per sh	*70.50*
5.91	6.23	6.98	7.40	6.33	5.19	4.69	5.34	6.70	6.13	*6.35*	*7.25*	"Cash Flow" per sh	*8.50*
2.74	2.76	4.07	4.09	3.51	2.48	1.58	2.28	3.24	2.88	*3.05*	*3.70*	Earnings per sh A	*4.25*
2.12	2.16	2.20	2.24	2.28	2.56	2.68	2.72	2.72	2.72	*2.72*	*2.72*	Div'd Decl'd per sh B ■	*2.80*
7.16	4.77	7.78	10.31	7.94	5.17	7.01	5.85	3.35	4.00	*8.30*	*9.85*	Cap'l Spending per sh	*9.00*
24.45	27.18	29.30	32.47	35.61	42.58	40.79	37.62	37.57	38.01	*38.45*	*39.50*	Book Value per sh C	*43.75*
32.01	36.91	37.26	40.16	43.06	75.99	75.99	75.98	77.35	77.91	*77.90*	*77.90*	Common Shs Outst'g D	*77.90*
14.0	14.9	11.5	13.4	14.7	21.4	30.7	14.8	14.7	17.5	*Bold figures are*		Avg Ann'l P/E Ratio	*12.0*
.76	.85	.61	.71	.79	1.14	1.85	.99	.94	1.11	*Value Line*		Relative P/E Ratio	*.80*
5.5%	5.3%	4.7%	4.1%	4.4%	4.8%	5.5%	8.1%	5.7%	5.4%	*estimates*		Avg Ann'l Div'd Yield	*5.6%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $2427.6 mill. **Due in 5 Yrs** $1199.0 mill.
LT Debt $1850.1 mill. **LT Interest** $102.9 mill.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $8.5 mill.
Pension Assets-12/11 $1.10 bill.
Oblig. $1.56 bill.
Pfd Stock $51.1 mill. **Pfd Div'd** $3.1 mill.
510,626 shs. 5.00% to 6.88%, callable $101 to $107.50; sinking fund began 11/1/79. All cumulative, $100 par.
Common Stock 77,916,543 shs.

MARKET CAP: $4.3 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
2674.9	4321.3	4890.6	6962.7	6890.7	10292	14048	7499.8	5203.2	4708.7	*4450*	*4900*	Revenues ($mill)	*5500*
94.4	94.5	156.2	157.4	151.6	181.1	124.8	178.2	255.9	230.9	*245*	*295*	Net Profit ($mill)	*340*
20.8%	26.3%	16.1%	22.9%	22.9%	32.2%	29.1%	41.5%	40.4%	36.7%	*38.5%*	*38.5%*	Income Tax Rate	*38.5%*
3.2%	2.5%	1.7%	1.0%	.5%	.7%	5.8%	4.5%	.7%	.4%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
48.3%	45.3%	43.1%	39.0%	44.8%	40.8%	42.1%	45.1%	42.2%	38.3%	*38.5%*	*41.5%*	Long-Term Debt Ratio	*43.5%*
45.8%	52.1%	54.4%	58.7%	53.4%	58.3%	57.0%	53.9%	56.8%	60.6%	*60.5%*	*57.5%*	Common Equity Ratio	*55.5%*
1708.3	1926.2	2008.6	2222.4	2871.9	5552.0	5438.7	5304.4	5118.5	4884.5	*4955*	*5340*	Total Capital ($mill)	*6125*
1610.2	1828.7	2002.6	2049.4	2534.8	4463.8	4773.3	4945.1	5013.4	5199.1	*5590*	*6090*	Net Plant ($mill)	*7300*
7.0%	6.1%	8.8%	8.0%	6.4%	4.5%	3.5%	4.6%	6.2%	5.9%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
10.7%	9.0%	13.7%	11.6%	9.6%	5.5%	4.0%	6.1%	8.7%	7.7%	*8.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
11.7%	9.1%	14.0%	11.8%	9.7%	5.5%	3.9%	6.1%	8.7%	7.7%	*8.0%*	*9.5%*	Return on Com Equity E	*10.0%*
3.1%	2.0%	6.6%	5.3%	3.4%	.0%	NMF	NMF	2.3%	.7%	*1.0%*	*2.5%*	Retained to Com Eq	*3.5%*
74%	79%	54%	56%	65%	99%	NMF	118%	74%	91%	*88%*	*72%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.3	+3.2	+.9
Avg. C & I Use (KWH)	NA	NA	NA
Avg. C & I Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	3346	3078	3312
Peak Load, Summer (Mw)	2403	2421	2465
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.4	+.4
Fixed Charge Cov. (%)	219	314	302

BUSINESS: Integrys Energy Group, Inc. is a holding company for Wisconsin Public Service, Peoples Gas, and four other utility subsidiaries. Has 493,000 electric customers in WI and MI, 1.7 million gas customers in WI, IL, MN, and MI. Also has retail electric and gas marketing operations in the Northeast and Midwest. Electric revenue breakdown: residential, 29%; small commercial & industrial, 29%; large commercial & industrial, 19%; other, 23%. Generating sources: coal, 53%; other, 5%; purchased, 42%. Fuel costs: 62% of revenues. '11 deprec. rates (utility): 2.2%-3.3%. Has 4,600 employees. Chairman, President & Chief Executive Officer: Charles A. Schrock. Inc.: WI. Address: 130 East Randolph St., Chicago, IL 60601-6207. Tel.: 312-228-5400. Internet: www.integrysgroup.com.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-13.5%	*-1.0%*
"Cash Flow"	1.0%	-2.5%	*6.0%*
Earnings	1.5%	-6.5%	*7.0%*
Dividends	3.0%	4.0%	*.5%*
Book Value	6.0%	3.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3201	1428	1298	1573	7499.8
2010	1903	1015	998	1287	5203.2
2011	1627	1011	939	1132	4708.7
2012	1251	*1000*	*1000*	*1199*	*4450*
2013	*1550*	*1050*	*1050*	*1250*	*4900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.89	.45	.63	.31	2.28
2010	.95	.82	.56	.91	3.24
2011	1.56	.38	.47	.48	2.88
2012	1.22	*.43*	*.45*	*.95*	*3.05*
2013	*1.70*	*.50*	*.50*	*1.00*	*3.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.67	.67	.67	.67	2.68
2009	.68	.68	.68	.68	2.72
2010	.68	.68	.68	.68	2.72
2011	.68	.68	.68	.68	2.72
2012	.68				

Integrys Energy's utility subsidiary in Wisconsin has filed a general rate case. Wisconsin Public Service requested electric and gas rate increases of $85.1 million (9.2%) and $12.8 million, respectively, based on a return of 10.3% on a common-equity ratio of 52.37%. WPS is also asking for a mechanism that would decouple revenues and volume. An order should come in time for new tariffs to take effect at the start of 2013.

Another regulatory matter is pending in the state. WPS is seeking regulatory approval to install pollution-control equipment at Weston 3, a 321-megawatt coal-fired unit, at an estimated cost of $250 million. A ruling is expected by the end of 2012.

A gas rate case is pending, and another is upcoming. In Minnesota, the utility is seeking a rate hike of $15 million (5.8%), based on a 10.75% return on a 50.48% common-equity ratio. The commission has issued a verbal order calling for an $11 million (4.3%) increase, based on a 9.7% return on the same common-equity ratio. New tariffs are scheduled to take effect this fall. In Illinois, Peoples Gas and North Shore Gas plan to file rate applications soon.

We have cut our 2012 earnings estimate by $0.40 a share, to $3.05. This was largely due to mark-to-market accounting charges in the first quarter, which reduced the bottom line by $0.33 a share. (These gains or losses, which are impossible to predict, hurt profits by $0.45 a share in 2011.) Also, an unusually mild winter lowered profits by an estimated $0.12 a share. Note that the company excludes mark-to-market items from its earnings guidance of $3.35-$3.55 a share.

We expect higher profits in 2013. The first-quarter comparison should be easy, assuming no mark-to-market losses and a return to normal weather patterns. Rate relief at the utilities should help. And the contribution of the energy services operation should climb as it picks up additional customers.

Integrys stock offers a dividend yield that is well above the utility average. However, with the quotation above the midpoint of our 2015-2017 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *June 22, 2012*

(A) Diluted EPS. Excl. nonrecur. losses: '09, $3.24; '10, 41¢ net; gains (loss) from disc. ops.: '07, $1.02; '08, 6¢; '09, 4¢; '11, (1¢); '12, 3¢. '11 EPS don't add due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid mid-Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '11: $29.74/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in WI in '11: 10.3%; in IL in '12: 9.45%; earned on avg. com. eq, '11: 7.7%. Regulatory Climate: WI, Above Average; IL, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	45
Earnings Predictability	45

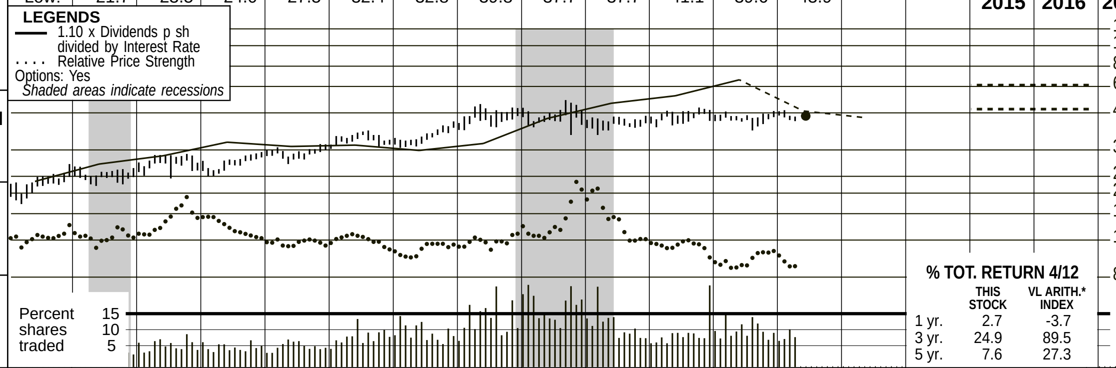
N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 46.38 | P/E RATIO 18.6 (Trailing: 19.6, Median: 17.0) | RELATIVE P/E RATIO 1.29 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS **4** Lowered 5/13/11
SAFETY **1** Raised 3/18/05
TECHNICAL **3** Raised 5/11/12
BETA .60 (1.00 = Market)

High:	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	46.5	50.9	49.0	49.5
Low:	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	37.7	41.1	39.6	43.9

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+40%)	*12%*
Low	50	(+10%)	*6%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	0	1
to Sell	0	0	1	0	2	0	2	0	1

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	54	54	72
to Sell	65	66	43
Hld's(000)	15895	16264	16071

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.7	-3.7
3 yr.	24.9	89.5
5 yr.	7.6	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	*32.20*	*32.15*	Revenues per sh	*41.95*
3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	*5.30*	*5.55*	"Cash Flow" per sh	*6.45*
1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	*2.50*	*2.70*	Earnings per sh A	*3.40*
1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	*1.78*	*1.82*	Div'ds Decl'd per sh B■	*1.94*
3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	*2.95*	*3.55*	Cap'l Spending per sh	*7.10*
15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	*27.80*	*28.25*	Book Value per sh D	*29.10*
22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	*27.00*	*28.00*	Common Shs Outst'g C	*31.00*
11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.20	*Value Line*		Relative P/E Ratio	*1.15*
5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*
						641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	812.1	848.8	*870*	*900*	Revenues ($mill)	*1300*
						43.8	46.0	50.6	58.1	65.2	74.5	68.5	75.1	72.7	63.9	*67.5*	*75.5*	Net Profit ($mill)	*105*
						34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
						6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	*7.8%*	*8.4%*	Net Profit Margin	*8.1%*
						47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	*45%*	*43%*	Long-Term Debt Ratio	*37%*
						51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	*55%*	*57%*	Common Equity Ratio	*63%*
						937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	*1370*	*1390*	Total Capital ($mill)	*1440*
						995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	*1955*	*2030*	Net Plant ($mill)	*2300*
						5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	*6.5%*	*7.0%*	Return on Total Cap'l	*8.5%*
						8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	*9.0%*	*9.5%*	Return on Shr. Equity	*11.5%*
						8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	*9.0%*	*9.5%*	Return on Com Equity	*11.5%*
						1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	*2.5%*	*3.0%*	Retained to Com Eq	*5.0%*
						79%	72%	69%	63%	59%	52%	59%	56%	61%	73%	*71%*	*67%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $755.4 mill. **Due in 5 Yrs** $200 mill.
LT Debt $641.7 mill. **LT Interest** $45.0 mill.

(Total interest coverage: 7.0x)

Pension Assets-12/10 $219 mill. **Oblig.** $337.3 mill.

Pfd Stock None

Common Stock 26,800,474 shares

MARKET CAP $1.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	3.5	5.8	4.0
Other	326.8	342.9	306.9
Current Assets	330.3	348.7	310.9
Accts Payable	93.2	86.3	60.2
Debt Due	267.4	181.6	113.7
Other	107.6	146.6	166.7
Current Liab.	468.2	414.5	340.6
Fix. Chg. Cov.	366%	334%	363%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	1.0%	*4.5%*
"Cash Flow"	3.0%	3.5%	*4.5%*
Earnings	4.0%	4.5%	*4.0%*
Dividends	3.0%	4.5%	*3.0%*
Book Value	4.0%	4.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	437.4	149.1	116.9	309.3	1012.7
2010	286.5	162.4	95.1	268.1	812.1
2011	323.1	161.2	93.3	271.2	848.8
2012	317.5	*160*	*100*	*292.5*	*870*
2013	*330*	*170*	*150*	*250*	*900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.78	.12	d.25	1.18	2.83
2010	1.64	.26	d.28	1.11	2.73
2011	1.53	.08	d.31	1.09	2.39
2012	1.51	*.15*	*d.50*	*1.34*	*2.50*
2013	*1.75*	*.15*	*d.30*	*1.10*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.395	1.52
2009	.395	.395	.395	.415	1.60
2010	.415	.415	.415	.435	1.68
2011	.435	.435	.435	.445	1.75
2012	.445	.445			

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 668,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 57%; commercial, 26%; industrial, gas transportation, and other, 17%. Employs 1,061. BlackRock Inc. owns 7.8% of shares; officers and directors, 1.7% (4/12 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Gas' profit is slated to modestly advance in 2012, despite higher-than-expected operational expenses. That said, revenue and earnings pulled back marginally in the first quarter, falling roughly 1% from the like period last year. As a result, we have decided to lower our 2012 and 2013 share-net estimates by $0.15 and $0.25, to $2.50 and $2.70, respectively.

The company continues to be active in Oregon. Along with its rate case (filed at the end of 2011, asking for a 6% rate increase), it is filing tariffs with the Oregon Public Utility Commission, as well as the Washington Utilities of Transportation Commission, for a refund of about $39 million (in gas cost savings to customers). Northwest Natural also filed a request with OPUC to provide Oregon customers with an additional $9 million in savings. All in all, management hopes these measures will strengthen the profitabilty in Oregon, enabling it to accelerate its bottom line growth.

Customer demand is growing modestly, but steadily. Residential and commercial customer count rose 1% in the March term, year over year, but industrial customer demand increased over 4% for the same period. The company hopes that the gain in customers (it added several new accounts in the forest products segment, and hopes to add more in the asphalt plant business as the year goes on) will help offset minor losses from low gas prices (via its storage segment).

Major projects are proceeding on schedule. The Encana venture is scheduled to begin operations by mid-decade, and is proceeding without obstacles thus far (24 new wells are likely to be drilled by the end of the year, with about 28% of the total investment of $250 million completed). The Gill Ranch expansion is also on track, and should considerably boost volume from 2013 onward. Both ventures should bolster the top and bottom lines, though we remain skeptical of their ability to fully offset the negative impact of a lukewarm economy.

We would pass on this untimely issue. This equity has subpar long-term appreciation potential, and its dividend yield is about in line with the industry average.

Sahana Zutshi *June 8, 2012*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢. Next earnings report due late July.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes Intangibles. In 2011: $371.4 million. $13.90/share.

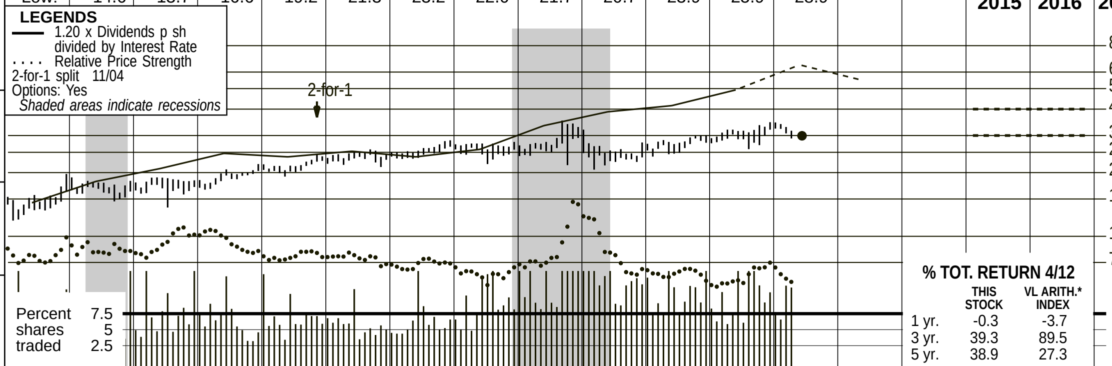
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	90

PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE 29.87 | P/E RATIO 17.8 (Trailing: 20.5 Median: 18.0) | RELATIVE P/E RATIO 1.24 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 4 Lowered 3/23/12
SAFETY 2 New 7/27/90
TECHNICAL 3 Raised 5/11/12
BETA .70 (1.00 = Market)

High:	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6
Low:	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.9



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+35%)	11%
Low	30	(Nil)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	1

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	70	87	85
to Sell	82	80	85
Hld's(000)	31155	32138	32579

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.3	-3.7
3 yr.	39.3	89.5
5 yr.	38.9	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	22.36	21.48	19.83	*19.85*	*22.85*	Revenues per sh A	*25.70*
1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	3.01	2.91	2.99	*3.00*	*3.20*	"Cash Flow" per sh	*3.45*
.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	1.57	*1.55*	*1.70*	Earnings per sh AB	*1.85*
.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	*1.19*	*1.23*	Div'ds Decl'd per sh C■	*1.35*
1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	1.76	2.75	3.37	*7.75*	*7.85*	Cap'l Spending per sh	*8.10*
6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	13.35	13.79	*13.90*	*13.95*	Book Value per sh D	*14.65*
59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	73.27	72.28	72.32	*71.00*	*70.00*	Common Shs Outst'g E	*68.00*
13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	15.4	17.1	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	*Value Line*		Relative P/E Ratio	*1.20*
4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	4.1%	4.2%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 1/31/12
Total Debt $1132.5 mill. **Due in 5 Yrs** $175.0 mill.
LT Debt $675.0 mill. **LT Interest** $46.1 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/11 $259.5 mill.
Oblig. $236.6 mill.
Pfd Stock None

Common Stock 71,685,958 shs.
as of 3/1/12
MARKET CAP: $2.1 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	*1340*	*1600*	Revenues ($mill) A	*1750*
62.2	74.4	95.2	101.3	97.2	104.4	110.0	122.8	111.8	113.6	*110*	*120*	Net Profit ($mill)	*125*
33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	*8.2%*	*7.5%*	Net Profit Margin	*7.3%*
43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	*43.0%*	*46.5%*	Long-Term Debt Ratio	*50.0%*
56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	*57.0%*	*53.5%*	Common Equity Ratio	*50.0%*
1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	*1730*	*1825*	Total Capital ($mill)	*1990*
1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	*2700*	*2750*	Net Plant ($mill)	*2900*
7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	*8.0%*	*8.5%*	Return on Total Cap'l	*8.5%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Shr. Equity	*13.0%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Com Equity	*13.0%*
1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	*2.5%*	*3.5%*	Retained to Com Eq	*3.5%*
83%	74%	66%	68%	74%	70%	69%	64%	72%	73%	*77%*	*72%*	All Div'ds to Net Prof	*72%*

CURRENT POSITION ($MILL.)	2010	2011	1/31/12
Cash Assets	5.6	6.8	10.1
Other	322.2	279.2	420.2
Current Assets	327.8	286.0	430.3
Accts Payable	115.7	129.7	135.3
Debt Due	302.0	331.0	457.5
Other	80.9	72.9	99.2
Current Liab.	498.6	534.1	692.0
Fix. Chg. Cov.	323%	323%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	-1.5%	*3.5%*
"Cash Flow"	5.5%	4.0%	*2.5%*
Earnings	5.0%	4.5%	*2.5%*
Dividends	4.5%	4.0%	*3.5%*
Book Value	5.0%	3.0%	*1.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	779.6	455.4	180.3	222.8	1638.1
2010	673.7	472.9	211.6	194.1	1552.3
2011	652.0	392.6	197.3	192.0	1433.9
2012	471.8	*415*	*225*	*228.2*	*1340*
2013	*535*	*480*	*290*	*295*	*1600*

Fiscal Year Ends	EARNINGS PER SHARE A B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	1.10	.73	d.10	d.06	1.67
2010	1.14	.65	d.13	d.13	1.55
2011	1.16	.66	d.12	d.13	1.57
2012	1.05	*.70*	*d.10*	*d.10*	*1.55*
2013	*1.18*	*.70*	*d.09*	*d.09*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.25	.26	.26	.26	1.03
2009	.26	.27	.27	.27	1.07
2010	.27	.28	.28	.28	1.11
2011	.28	.29	.29	.29	1.15
2012	.29	.30			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 968,188 customers in North Carolina, South Carolina, and Tennessee. 2011 revenue mix: residential (46%), commercial (27%), industrial (7%), other (20%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 60.0% of revenues. '11 deprec. rate: 3.2%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,782 employees. Off./dir. own about 1.2% of common stock, BlackRock; 7.6% (1/12 proxy). Chrmn., CEO, & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas posted lower-than-expected financial results for the first quarter of fiscal 2012 (ended January 31st). Warmer weather than normal versus the prior year was a factor. Elsewhere, on the profitability front, operating expenses increased as a percentage of the top line by 740 basis points. Additional detractors stemmed from lower "other" income, particularly from PNY's stakes in equity-method investments. On balance, the bottom line declined about 9.5%, to $1.05 a share. Consequently,

We have trimmed a dime off our 2012 share-net estimate. The diminished top line can largely be viewed as a technicality, because utility companies pass the cost of gas through to the end-use customers. However, the margin compression, and weakness in other income, will likely result in a slight, low single-digit earnings decline this year.

But bottom line gains may resume next year. This ought to be supported by additions in the company's residential and commercial customers, thanks to new construction in those markets. New power generation customers will be added when construction is completed on a pair of projects. One is due to come on line this month, and the other a year from now.

Meanwhile, the balance sheet continues to improve. During the first quarter, cash reserves increased almost 50%. That financial cushion now sits at roughly $10.1 million. At the same time, the long-term debt load has remained constant at about 40% of the total capital structure and should be well within manageable levels. In fact, that form of funding has been on the decline since the middle of the last decade. What's more, the board recently approved a hike in the quarterly dividend of 3.4%, to $0.30 a share.

These shares have logged a price correction of about 9.5% since our March review. In comparison, the S&P 500 Index declined only about 4% for that same interim. This move is in contrast to what we would expect from a stock with a below-market Beta.

Still, at its present quotation, the untimely stock may appeal to income-oriented investors, thanks to its slightly above-average dividend yield.

Bryan J. Fong *June 8, 2012*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '97, (2¢); '10, 41¢. Next earnings report due mid June. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid early-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2011: $527.6 million, $7.29/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

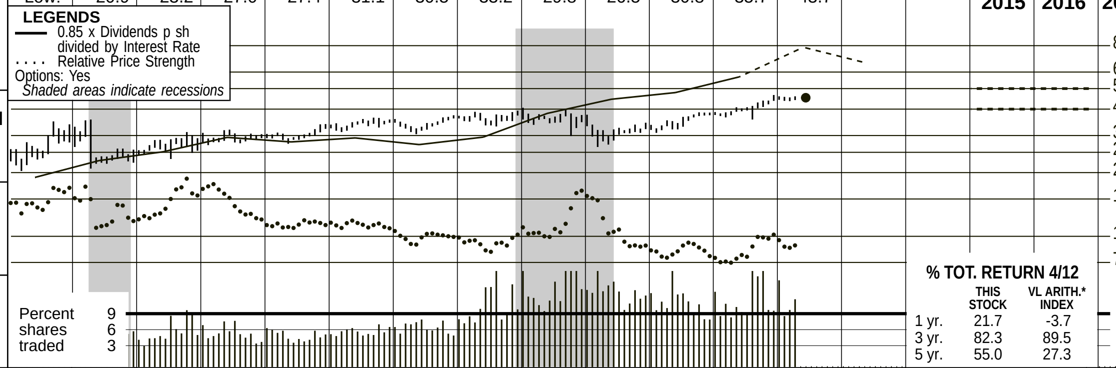
SOUTHERN CO. NYSE-SO

RECENT PRICE	45.40	P/E RATIO	17.8 (Trailing: 18.3 / Median: 15.0)	RELATIVE P/E RATIO	1.24	DIV'D YLD	4.4%	VALUE LINE

TIMELINESS 3 Lowered 2/3/12
SAFETY 1 Raised 6/3/05
TECHNICAL 3 Raised 5/18/12
BETA .55 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
High:	35.7	31.1	32.0	34.0	36.5	37.4	39.3	40.6	37.6	38.6	46.7	46.3
Low:	20.9	23.2	27.0	27.4	31.1	30.5	33.2	29.8	26.5	30.8	35.7	43.7

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	7%
Low	40	(-10%)	2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	1
Options	0	0	3	1	2	1	0	1	0
to Sell	0	0	3	1	2	1	0	1	0

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	396	435	435
to Sell	298	281	307
Hld's(000)	372740	373196	374903

% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.7	-3.7
3 yr.	82.3	89.5
5 yr.	55.0	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
15.30	18.19	16.34	17.40	14.78	14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	**18.40**	**18.95**	Revenues per sh	**21.25**
3.64	3.86	4.26	4.17	3.89	3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	**5.00**	**5.30**	"Cash Flow" per sh	**6.00**
1.68	1.58	1.73	1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	**2.55**	**2.75**	Earnings per sh A	**3.25**
1.26	1.30	1.34	1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	**1.94**	**2.02**	Div'd Decl'd per sh B ■ †	**2.25**
1.82	2.68	2.87	3.85	3.27	3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	**6.45**	**6.10**	Cap'l Spending per sh	**6.75**
13.61	13.91	14.04	13.82	15.69	11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	**21.15**	**22.25**	Book Value per sh C	**26.25**
677.04	693.42	697.75	665.80	681.16	698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	**875.00**	**885.00**	Common Shs Outst'g D	**940.00**
13.8	14.0	15.7	14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	*Bold figures are*		Avg Ann'l P/E Ratio	**14.0**
.86	.81	.82	.82	.86	.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	1.00	*Value Line*		Relative P/E Ratio	**.95**
5.5%	5.9%	4.9%	5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	*estimates*		Avg Ann'l Div'd Yield	**5.0%**

CAPITAL STRUCTURE as of 12/31/11
Total Debt $21223 mill. **Due in 5 Yrs** $7525.0 mill.
LT Debt $18647 mill. **LT Interest** $830.0 mill.
(LT interest earned: 4.9x)
Leases, Uncapitalized Annual rentals $121.0 mill.
Pension Assets-12/11 $6.80 bill. **Oblig.** $8.08 bill.
Pfd Stock $1082 mill. **Pfd Div'd** $65.0 mill.
Incl. 1 mill. shs. 4.20%-5.44% cum. pfd. ($100 par); 12 mill. shs. 4.95%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 3 mill. shs. 6.0%-6.5% noncum. pfd. ($100 par); 14 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 866,573,913 shs. **as of 1/31/12**
MARKET CAP: $39 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
10549	11251	11902	13554	14356	15353	17127	15743	17456	17657	**16100**	**16750**	Revenues ($mill)	**20000**
1510.0	1602.1	1589.0	1621.0	1608.0	1782.0	1807.0	1910.0	2040.0	2268.0	**2295**	**2490**	Net Profit ($mill)	**3095**
25.9%	27.0%	27.0%	26.9%	32.7%	31.9%	33.6%	31.9%	33.5%	35.0%	**32.0%**	**32.0%**	Income Tax Rate	**32.0%**
5.4%	4.6%	5.2%	4.4%	4.8%	9.5%	12.3%	14.9%	13.7%	10.2%	**13.0%**	**13.0%**	AFUDC % to Net Profit	**12.0%**
43.1%	45.9%	53.5%	53.2%	50.8%	51.2%	53.9%	53.2%	51.2%	50.0%	**51.0%**	**52.0%**	Long-Term Debt Ratio	**52.0%**
43.4%	43.6%	44.1%	44.3%	46.2%	44.9%	42.6%	43.6%	45.7%	47.1%	**46.0%**	**45.5%**	Common Equity Ratio	**46.0%**
20086	22135	23288	24131	24618	27608	31174	34091	35438	37307	**40150**	**43300**	Total Capital ($mill)	**53600**
24642	27534	28361	29480	31092	33327	35878	39230	42002	45010	**48500**	**51625**	Net Plant ($mill)	**63500**
8.6%	8.4%	8.1%	8.2%	8.2%	7.9%	7.1%	6.9%	7.0%	7.2%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
13.2%	13.4%	14.7%	14.4%	13.3%	13.2%	12.6%	12.0%	11.8%	12.2%	**11.5%**	**12.0%**	Return on Shr. Equity	**12.0%**
15.1%	14.8%	14.9%	14.9%	13.8%	14.0%	13.1%	12.4%	12.2%	12.5%	**12.0%**	**12.5%**	Return on Com Equity E	**12.5%**
4.1%	4.4%	4.7%	4.6%	3.8%	4.3%	3.5%	3.2%	3.0%	3.4%	**3.0%**	**3.5%**	Retained to Com Eq	**4.0%**
76%	73%	69%	70%	73%	70%	74%	75%	77%	73%	**76%**	**74%**	All Div'ds to Net Prof	**70%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.8	+7.6	-2.7
Avg. Indust. Use (MWH)	3095	3332	3438
Avg. Indust. Revs. per KWH (¢)	6.04	6.20	6.37
Capacity at Yearend (Mw)	42932	42963	43555
Peak Load, Summer (Mw)	34471	36321	36956
Annual Load Factor (%)	60.6	62.2	59.0
% Change Customers (yr-end)	- -	+.3	-.1
Fixed Charge Cov. (%)	310	342	397

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.5%	2.5%	*1.0%*
"Cash Flow"	2.0%	3.5%	*4.5%*
Earnings	3.0%	3.0%	*5.0%*
Dividends	3.0%	4.0%	*4.0%*
Book Value	3.5%	6.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3666	3885	4682	3510	15743
2010	4157	4208	5320	3771	17456
2011	4012	4521	5428	3696	17657
2012	3604	***3796***	***5000***	***3700***	***16100***
2013	***3800***	***3950***	***5200***	***3800***	***16750***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.41	.61	.99	.31	2.32
2010	.60	.62	.98	.18	2.36
2011	.49	.70	1.06	.30	2.55
2012	.42	***.65***	***1.15***	***.33***	***2.55***
2013	***.48***	***.78***	***1.15***	***.34***	***2.75***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.4025	.42	.42	.42	1.66
2009	.42	.4375	.4375	.4375	1.73
2010	.4375	.455	.455	.455	1.80
2011	.455	.4725	.4725	.4725	1.87
2012	.4725	.49			

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Also has competitive generation business. Electric revenue breakdown: residential, 35%; commercial, 30%; industrial, 19%; wholesale, 11%; other, 5%. Retail revenues by state: Georgia, 51%; Alabama, 33%; Florida, 9%; Mississippi, 7%. Generating sources: coal, 49%; oil & gas, 28%; nuclear, 15%; hydro, 2%; purchased, 6%. Fuel costs: 39% of revenues. '11 reported deprec. rate (utility): 3.2%. Has 26,400 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southerncompany.com.

We estimate that Southern Company's earnings will be flat in 2012. Warmer-than-normal weather patterns hurt March-quarter profits by $0.06 a share. Also, since favorable weather benefited the company in the second period of 2011, earnings will probably decline in the same period of 2012, assuming normal weather conditions. We have trimmed our 2012 share-earnings estimate by $0.10, to $2.55. This is below Southern's targeted range of $2.58-$2.70, which is based on normal weather.

Gulf Power received a rate increase. The Florida regulators granted the utility a rate hike of $64.1 million. The allowed return on equity is in a range of 9.25%-11.25%. New tariffs took effect in April. A step increase of $4.0 million will occur in January of 2013.

We figure that earnings will advance in 2013. We base our forecast on a return to normal weather in the March quarter. Kilowatt-hour sales should advance as the economic recovery continues. Rate relief will help, too. Besides Gulf Power's rate order, Georgia Power will get the final step of a multiyear tariff hike that runs through 2013. Alabama Power and Mississippi Power have formula rate plans that usually provide rate hikes.

As we had expected, the board of directors raised the dividend in the second quarter. The directors boosted the annual payout by $0.07 a share (3.7%).

Two major projects are under construction. Georgia Power will own a 45.7% stake (about 1,000 megawatts) in two nuclear units. The company's share of this project is projected at $6.1 billion, and the new facilities are scheduled to go into service in 2016 and 2017. Mississippi Power is building a 582-mw coal gasification plant at a projected cost of $2.4 billion. It is due on line in 2014. Management states that the expected in-service dates and budgets are still achievable, but we have become more worried about possible delays or cost overruns.

Even after the dividend increase, this top-quality stock's yield is only average for a utility. With the quotation above the midpoint of our 2015-2017 Target Price Range, total return potential over that time frame is subpar.

Paul E. Debbas, CFA *May 25, 2012*

(A) Diluted earnings. Excl. nonrecurring gain (loss): '03, 6¢; '09, (25¢). '10 EPS don't add due to change in shares. Next earnings report due late July. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '11: $6.27/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on com. eq. (blended): 12.5%. Earned on avg. com. eq., '11: 13.0%. Regulatory Climate: AL Above Average; GA, MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	100

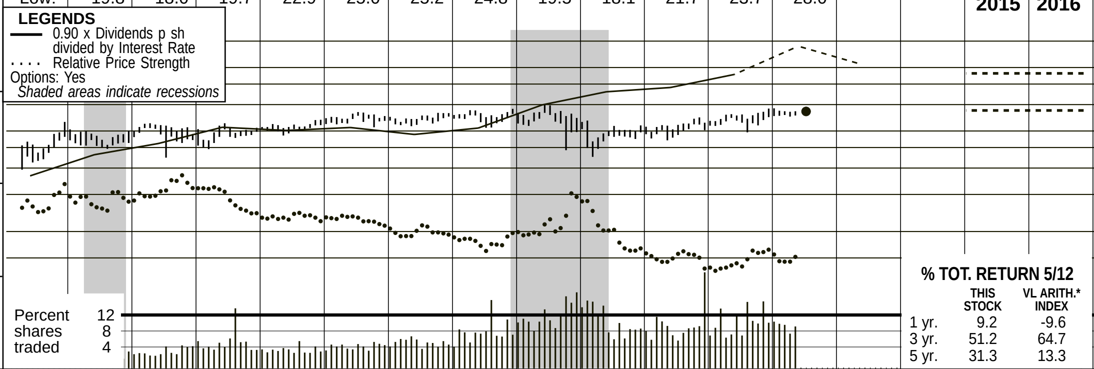
VECTREN CORP. NYSE-VVC

RECENT PRICE **29.62** | P/E RATIO **16.0** (Trailing: 16.5 / Median: 15.0) | RELATIVE P/E RATIO **1.12** | DIV'D YLD **4.8%** | VALUE LINE

High:	24.4	26.1	26.1	27.1	29.5	29.3	30.5	32.2	26.9	27.8	30.7	30.7
Low:	19.8	18.0	19.7	22.9	25.0	25.2	24.8	19.5	18.1	21.7	23.7	28.0

TIMELINESS 3 Lowered 2/24/12
SAFETY 2 Lowered 1/5/01
TECHNICAL 3 Raised 5/18/12
BETA .75 (1.00 = Market)

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+50%)	14%
Low	30	(Nil)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	7	2	0	0	0
to Sell	0	0	0	0	8	2	0	1	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	98	103	127
to Sell	90	87	84
Hld's(000)	42996	44409	45722

% TOT. RETURN 5/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	-9.6
3 yr.	51.2	64.7
5 yr.	31.3	13.3

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
26.53	21.00	22.26	26.62	26.83	29.88	30.67	25.76	26.06	28.39	**28.65**	**30.00**	Revenues per sh	**33.50**
3.43	3.17	3.27	3.87	3.69	4.29	3.97	4.40	4.44	4.72	**5.00**	**5.50**	"Cash Flow" per sh	**6.75**
1.68	1.56	1.42	1.81	1.44	1.83	1.63	1.79	1.64	1.73	**1.85**	**2.00**	Earnings per sh A	**2.50**
1.07	1.11	1.15	1.19	1.23	1.27	1.31	1.35	1.37	1.39	**1.41**	**1.43**	Div'd Decl'd per sh B■†	**1.60**
3.22	3.12	3.66	3.04	3.70	4.38	4.83	5.33	3.39	3.92	**4.50**	**5.35**	Cap'l Spending per sh	**6.80**
12.79	14.18	14.42	15.01	15.43	16.16	16.68	17.23	17.61	17.89	**18.65**	**19.35**	Book Value per sh C	**21.00**
68.01	75.60	75.90	76.19	76.10	76.36	81.03	81.10	81.70	81.90	**83.00**	**84.00**	Common Shs Outst'g D	**88.00**
14.2	14.8	17.6	15.1	18.9	15.3	16.8	12.9	15.1	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	**15.0**
.78	.84	.93	.80	1.02	.81	1.01	.86	.96	.97	*Value Line*		Relative P/E Ratio	**1.00**
4.5%	4.8%	4.6%	4.4%	4.5%	4.5%	4.8%	5.9%	5.5%	5.5%	*estimates*		Avg Ann'l Div'd Yield	**4.3%**
1804.3	1587.6	1689.8	2028.0	2041.6	2281.9	2484.7	2088.9	2129.5	2325.2	**2380**	**2520**	Revenues ($mill)	**2950**
114.0	111.2	108.0	136.8	108.8	143.1	129.0	145.0	133.7	141.6	**155**	**170**	Net Profit ($mill)	**220**
25.4%	25.3%	26.5%	24.4%	21.8%	34.7%	37.1%	26.5%	35.8%	37.9%	**37.0%**	**36.0%**	Income Tax Rate	**35.0%**
4.6%	4.5%	3.0%	1.4%	3.8%	2.8%	2.9%	4.1%	4.1%	4.0%	**3.5%**	**3.5%**	AFUDC % to Net Profit	**3.5%**
52.3%	50.0%	48.1%	51.2%	50.7%	50.2%	48.0%	52.4%	49.9%	51.6%	**51.0%**	**52.0%**	Long-Term Debt Ratio	**52.0%**
47.7%	50.0%	51.8%	48.8%	49.3%	49.8%	52.0%	47.6%	50.1%	48.4%	**49.0%**	**48.0%**	Common Equity Ratio	**48.0%**
1824.4	2144.7	2111.5	2341.3	2382.2	2479.1	2599.5	2937.7	2874.1	3025.0	**3150**	**3375**	Total Capital ($mill)	**3850**
1648.1	2003.7	2156.2	2251.9	2385.5	2539.7	2720.3	2878.8	2955.4	3032.6	**3100**	**3200**	Net Plant ($mill)	**3500**
7.7%	6.6%	6.4%	7.2%	6.0%	7.2%	6.5%	6.3%	6.1%	6.1%	**6.5%**	**6.5%**	Return on Total Cap'l	**7.0%**
13.1%	10.4%	9.9%	12.0%	9.3%	11.6%	9.5%	10.4%	9.3%	9.5%	**10.0%**	**10.5%**	Return on Shr. Equity	**12.0%**
13.1%	10.4%	9.9%	12.0%	9.3%	11.6%	9.5%	10.4%	9.3%	9.7%	**10.0%**	**10.5%**	Return on Com Equity E	**12.0%**
4.8%	3.0%	1.9%	4.0%	1.3%	3.8%	2.0%	2.6%	1.6%	1.9%	**2.5%**	**3.0%**	Retained to Com Eq	**4.5%**
63%	71%	81%	66%	86%	67%	80%	75%	83%	80%	**76%**	**71%**	All Div'ds to Net Prof	**64%**

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1795.6 mill. **Due in 5 Yrs** $625.5 mill.
LT Debt $1559.3 mill. **LT Interest** $90.0 mill.
(LT interest earned: 3.3x)

Pension Assets-12/11 $261.0 mill.
Oblig. $329.2 mill.
Pfd Stock None

Common Stock 81,993,361 shs.
as of 4/30/12

MARKET CAP: $2.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-5.3	11.5	-.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1493	1496	1494
Peak Load, Summer (Mw)	1143	1275	1220
Annual Load Factor (%)	56.2	58.1	57.1
% Change Customers (yr-end)	-.2	+.3	- -
Fixed Charge Cov. (%)	280	303	347

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.5%	3.5%	4.0%
"Cash Flow"	4.0%	4.5%	7.0%
Earnings	2.5%	1.0%	6.5%
Dividends	3.5%	3.0%	2.5%
Book Value	4.0%	3.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	795.2	375.5	349.6	568.6	2088.9
2010	740.3	402.4	422.7	564.1	2129.5
2011	682.6	475.8	539.4	627.4	2325.2
2012	604.6	**505**	**560**	**710.4**	**2380**
2013	**700**	**525**	**575**	**720**	**2520**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.90	.07	.15	.67	1.79
2010	.78	.11	.20	.55	1.64
2011	.55	.18	.43	.56	1.73
2012	.62	**.20**	**.40**	**.63**	**1.85**
2013	**.65**	**.25**	**.45**	**.65**	**2.00**

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.325	.325	.325	.335	1.31
2009	.335	.335	.335	.340	1.35
2010	.340	.340	.340	.345	1.37
2011	.345	.345	.345	.350	1.39
2012	.350	.350			

BUSINESS: Vectren is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base of 1,134,900. 2011 Electricity revenues: residential, 36%; commercial, 27%; industrial, 36%; other, 1%. 2011 Gas revenues: residential, 67%; commercial, 24%; other, 9%. Also provides energy-related products and services and has an investment subsidiary. Est'd plant age: electric, 8 years. '11 deprec. rate: 4.9%. Has 4,500 employees. Chairman, President, & CEO: Carl Chapman. Incorporated: IN. Address: One Vectren Square, Evansville, Indiana 47708. Telephone: 812-491-4000. Internet: www.vectren.com.

Shares of Vectren have traded in a fairly narrow range since the beginning of the year. The company posted mixed results for the first quarter. The utility operations benefited from higher base rates, though this was partly offset by unusually mild winter weather. Good performance at the Infrastructure Services line was countered by losses at the Energy Services and Coal Mining businesses. Overall, the top line declined in both the utility and nonutility operations. However, this was more than offset by lower operating expenses, and share net of $0.62 compared favorably with the prior-year tally.

The utility group should further experience solid bottom-line performance going forward. This assumes normal weather for the remainder of the year in Vectren's electric service territories. Temperature fluctuations in the company's gas service territories are largely mitigated through regulatory mechanisms. Elsewhere, the Infrastructure Services business ought to continue to post good results. This line should further benefit from healthy demand for work on transmission pipeline repairs, and other services, too. Construction activity will probably remain strong as utilities and pipeline operators replace their aging natural gas and oil infrastructure, and as the demand for additional shale gas and oil infrastructure increases. That said,

Results will probably be less favorable in other segments. The company's coal mining operations may well experience further weakness. Moreover, unfavorable market conditions will probably continue to result in depressed asset optimization opportunities at gas-marketer ProLiance. On the bright side, efforts to deemphasize the commodities business (such as the sale of Vectren Source) ought to pay off going forward. Overall, we expect higher revenues and share earnings for the company in the current year, and respectable growth in 2013.

This equity remains neutrally ranked for Timeliness. We anticipate steady growth in revenues and share earnings for the company over the pull to 2015-2017. From the recent quotation, this issue has worthwhile total return potential, given the healthy dividend payout.

Michael Napoli, CFA *June 22, 2012*

(A) Diluted EPS. Excl. nonrecur. gain (loss): '01, (13¢); '03, (6¢); '09, 15¢. Earnings may not sum due to rounding. Next egs report due early August. (B) Div'ds historically paid in early March, June, September, and December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '11, $5.96/sh. (D) In millions. (E) Electric rate base determination: fair value. Rates allowed on elect. common equity range from 10.15% to 10.4%; earned on common equity in '11: 9.7%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	90

WGL HOLDINGS NYSE-WGL

RECENT PRICE 38.67 | P/E RATIO 15.3 (Trailing: 16.0 Median: 15.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 9/9/11
SAFETY 1 Raised 4/2/93
TECHNICAL 3 Raised 6/1/12
BETA .65 (1.00 = Market)

High:	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0
Low:	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6	31.0	34.7	37.9

Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

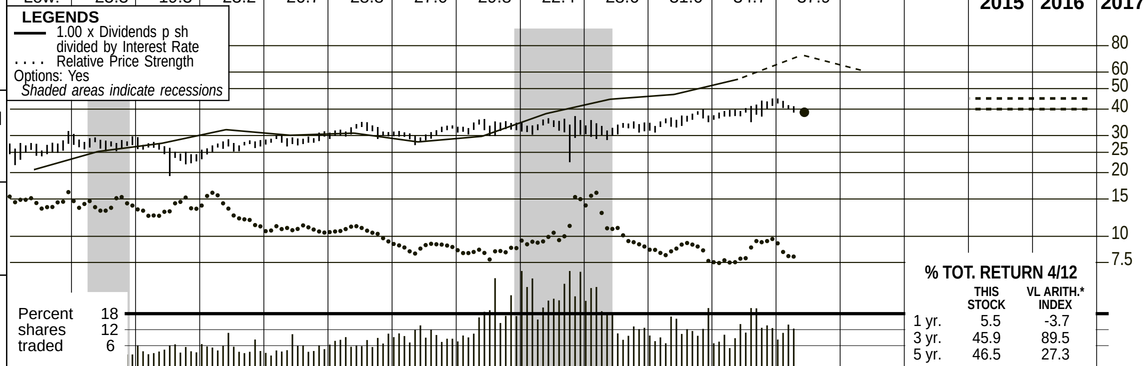
	Price	Gain	Ann'l Total Return
High	45	(+15%)	8%
Low	40	(+5%)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	1	0	0	0	0
to Sell	0	1	0	0	1	0	0	1	0

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	86	85	88
to Sell	72	84	80
Hld's(000)	29975	31165	31882



% TOT. RETURN 4/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.5	-3.7
3 yr.	45.9	89.5
5 yr.	46.5	27.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	53.75	*50.30*	*55.05*	Revenues per sh A	*59.90*
2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	*4.40*	*4.45*	"Cash Flow" per sh	*4.70*
1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	*2.50*	*2.55*	Earnings per sh B	*2.80*
1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	*1.59*	*1.63*	Div'ds Decl'd per sh C■	*1.75*
2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	*5.85*	*4.85*	Cap'l Spending per sh	*4.80*
12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	21.89	22.82	23.49	*24.50*	*25.60*	Book Value per sh D	*28.65*
43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	*51.50*	*51.75*	Common Shs Outst'g E	*52.00*
11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	17.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	*Value Line*		Relative P/E Ratio	*1.00*
5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $742.8 mill. **Due in 5 Yrs** $189.2 mill.
LT Debt $585.8 mill. **LT Interest** $40.0 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x)
Pension Assets-9/11 $1,289.0 mill. **Oblig.** $896.5 mill.
Preferred Stock $28.2 mill. **Pfd. Div'd** $1.3 mill.

Common Stock 51,535,032 shs. **as of 4/30/12**

MARKET CAP: $2.0 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	*2590*	*2850*	Revenues ($mill) A	*3115*
55.7	112.3	98.0	104.8	96.0	102.9	122.9	128.7	115.0	115.5	*129*	*132*	Net Profit ($mill)	*145*
34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	*5.0%*	*4.6%*	Net Profit Margin	*4.7%*
45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	*31.0%*	*30.5%*	Long-Term Debt Ratio	*28.5%*
52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	*67.5%*	*68.5%*	Common Equity Ratio	*70.5%*
1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	1687.7	1774.4	1818.1	*1875*	*1935*	Total Capital ($mill)	*2115*
1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	*2640*	*2805*	Net Plant ($mill)	*3350*
5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	*10.0%*	*10.0%*	Return on Com Equity	*10.0%*
NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
112%	56%	65%	62%	69%	66%	57%	57%	67%	64%	*64%*	*64%*	All Div'ds to Net Prof	*62%*

CURRENT POSITION ($MILL.)	2010	2011	3/31/12
Cash Assets	8.9	4.3	97.2
Other	708.4	720.4	844.0
Current Assets	717.3	724.7	941.2
Accts Payable	225.4	279.4	258.8
Debt Due	130.5	116.5	157.0
Other	188.2	180.8	289.5
Current Liab.	544.1	576.7	705.3
Fix. Chg. Cov.	536%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.5%	2.5%	*2.0%*
"Cash Flow"	3.0%	1.5%	*2.0%*
Earnings	3.0%	3.0%	*3.0%*
Dividends	2.0%	2.5%	*2.5%*
Book Value	4.0%	5.0%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	826.2	1040.9	427.0	412.8	2706.9
2010	727.4	1056.6	459.7	465.2	2708.9
2011	795.9	1017.2	490.3	448.1	2751.5
2012	727.8	839.4	*525*	*497.8*	*2590*
2013	*740*	*1060*	*535*	*515*	*2850*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.03	1.65	.11	d.25	2.53
2010	1.01	1.64	d.07	d.29	2.27
2011	1.02	1.53	d.03	d.26	2.25
2012	1.13	1.58	*.01*	*d.22*	*2.50*
2013	*1.15*	*1.60*	*Nil*	*d.20*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.34	.36	.36	.36	1.42
2009	.36	.37	.37	.37	1.47
2010	.37	.378	.378	.378	1.50
2011	.378	.39	.39	.39	1.55
2012	.39	.40			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,082,983 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. Black Rock Inc. owns 7.4% of common stock; Off./dir. less than 1% (1/12 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings posted a mixed bag of financial results for the March period. The top line declined 17.5% due to lower utility and nonutility revenues. This reflected warmer-than-normal weather patterns. Meanwhile, on the profitability front, operating expenses declined 240 basis points, as a percentage of the top line. Combined, these factors raised the bottom line 3.3%, to $1.58 a share.

The company is on pace to log a nice double-digit earnings advance this year. This ought to stem from larger contributions from the Regulated Utility and Commercial Energy System divisions. The former is benefiting from the implementation of rate increases in Virginia and Maryland, as well as from a rising number of customer accounts. The latter should get a boost from higher revenue from commercial solar projects and a much anticipated commencement of government projects that have been delayed for some time now. On the downside, the Retail Energy-Marketing segment has not been performing as well. That unit is facing lower realized natural gas margins and retail sales volumes as a result of warmer-than-normal weather patterns. Nonetheless, the positive gains from the company's other units should be more than capable of driving this year's bottom line higher.

WGL recently opened a new electric generation facility. That plant, located in northern Virginia, will convert natural gas to electricity. It is a concerted effort by the company to focus on green energy production and should lower its overall carbon footprint while powering the grid.

The overall financial position is in good shape. Indeed, WGL's cash reserves increased almost 23-fold during the first quarter of the year. However, that is likely a reflection of a higher reliance on short-term notes payable. Meanwhile, the long-term debt load has remained relatively constant and represents about 30% of the capital structure. What's more, the company recently increased its quarterly dividend by roughly 2.5%, to $0.40 a share.

These shares may appeal to income-seeking accounts. Also, since our March review, WGL has logged a price correction of 5%, which may offer an attractive entry point into these high-yielding shares.

Bryan J. Fong *June 8, 2012*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late July. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '11: $594.4 million, $11.56/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	95

WISCONSIN ENERGY NYSE-WEC

RECENT PRICE 38.87 | P/E RATIO 17.3 (Trailing: 17.7 Median: 14.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Lowered 1/13/12

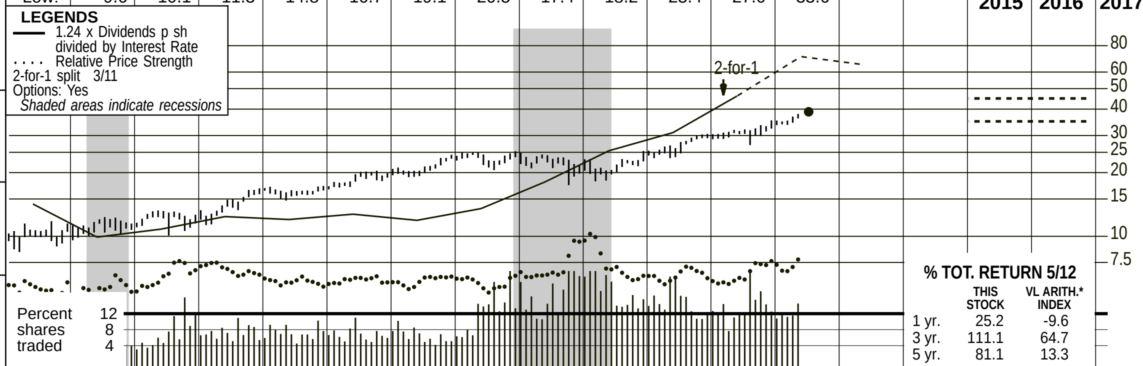
SAFETY 1 Raised 3/23/12

TECHNICAL 4 Lowered 6/22/12

BETA .65 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	12.3	13.2	16.8	17.3	20.4	24.3	25.2	24.8	25.3	30.5	35.4	38.9
Low:	9.6	10.1	11.3	14.8	16.7	19.1	20.5	17.4	18.2	23.4	27.0	33.6

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	35	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	2	4	0	2	0	2	3
to Sell	0	1	3	4	0	2	0	4	3

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	178	188	191
to Sell	158	175	178
Hld's(000)	159649	158257	157172

% TOT. RETURN 5/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.2	-9.6
3 yr.	111.1	64.7
5 yr.	81.1	13.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
7.94	7.93	8.56	9.56	14.14	17.02	16.10	17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.46	***18.50***	***20.40***	**Revenues per sh**	***23.25***
2.13	1.48	2.06	2.26	2.24	2.72	2.84	2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.68	***3.85***	***4.30***	**"Cash Flow" per sh**	***5.00***
.99	.27	.83	.94	.54	.92	1.16	1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	2.18	***2.25***	***2.40***	**Earnings per sh A**	***2.75***
.75	.77	.78	.78	.69	.40	.40	.40	.42	.44	.46	.50	.54	.68	.80	1.04	***1.20***	***1.36***	**Div'd Decl'd per sh B ■**	***1.80***
1.77	1.56	1.76	2.22	2.64	3.01	2.54	2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	3.60	***3.30***	***3.20***	**Cap'l Spending per sh**	***3.25***
8.71	8.25	8.23	8.44	8.50	8.91	9.22	9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.20	***17.95***	***18.15***	**Book Value per sh C**	***20.25***
223.36	225.73	231.21	237.81	237.29	230.84	232.06	236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	230.49	***230.00***	***223.00***	**Common Shs Outst'g D**	***223.00***
14.3	47.3	18.0	13.3	18.7	12.1	10.5	12.4	17.5	14.5	16.0	16.5	14.8	13.3	14.0	14.2	*Bold figures are*		**Avg Ann'l P/E Ratio**	***14.5***
.90	2.73	.94	.76	1.22	.62	.57	.71	.92	.77	.86	.88	.89	.89	.89	.90	*Value Line*		**Relative P/E Ratio**	***.95***
5.4%	6.0%	5.2%	6.3%	6.8%	3.6%	3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	*estimates*		**Avg Ann'l Div'd Yield**	***4.5%***

CAPITAL STRUCTURE as of 3/31/12

Total Debt $5193.9 mill. **Due in 5 Yrs** $1800.4 mill.
LT Debt $4602.8 mill. **LT Interest** $257.8 mill.
Incl. $120.0 mill. capitalized leases.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $16.3 mill.
Pension Assets-12/11 $1.26 bill. **Oblig.** $1.33 bill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable at $101; 44,498 shs. 6%, $100 par.
Common Stock 230,455,017 shs.

MARKET CAP: $9.0 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
3736.2	4054.3	3431.1	3815.5	3996.4	4237.8	4431.0	4127.9	4202.5	4486.4	***4250***	***4550***	**Revenues ($mill)**	***5200***
270.8	269.2	221.2	304.8	313.7	337.7	359.8	378.4	455.6	514.0	***525***	***555***	**Net Profit ($mill)**	***645***
37.4%	35.5%	37.5%	32.9%	35.8%	39.1%	37.6%	36.5%	35.4%	33.9%	***36.5%***	***36.5%***	**Income Tax Rate**	***36.5%***
4.1%	6.9%	10.0%	12.5%	19.0%	23.8%	27.2%	25.0%	18.6%	16.4%	***10.0%***	***7.0%***	**AFUDC % to Net Profit**	***6.0%***
59.8%	59.9%	56.2%	52.8%	51.3%	50.3%	54.8%	51.9%	50.6%	53.6%	***53.0%***	***54.0%***	**Long-Term Debt Ratio**	***53.0%***
39.6%	39.6%	43.3%	46.7%	48.2%	49.2%	44.8%	47.7%	49.0%	46.0%	***46.5%***	***45.5%***	**Common Equity Ratio**	***46.5%***
5400.3	5963.3	5762.3	5741.5	5992.8	6302.1	7442.0	7473.1	7764.5	8608.0	***8880***	***8890***	**Total Capital ($mill)**	***9650***
4398.8	5926.1	5903.1	6362.9	7052.5	7681.2	8517.0	9070.5	9601.5	10160	***10555***	***10870***	**Net Plant ($mill)**	***11525***
7.1%	6.3%	5.6%	7.0%	6.6%	7.0%	6.3%	6.4%	7.5%	7.5%	***7.5%***	***7.5%***	**Return on Total Cap'l**	***8.0%***
12.5%	11.3%	8.8%	11.2%	10.7%	10.8%	10.7%	10.5%	11.9%	12.9%	***12.5%***	***13.5%***	**Return on Shr. Equity**	***14.0%***
12.6%	11.4%	8.8%	11.3%	10.8%	10.9%	10.7%	10.6%	12.0%	12.9%	***12.5%***	***13.5%***	**Return on Com Equity E**	***14.0%***
8.3%	7.4%	4.9%	7.5%	7.1%	7.1%	7.0%	6.2%	7.0%	6.8%	***6.0%***	***6.0%***	**Retained to Com Eq**	***5.5%***
35%	35%	45%	34%	35%	35%	35%	42%	41%	47%	***53%***	***56%***	**All Div'ds to Net Prof**	***63%***

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-8.1	+6.0	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.57	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5812	5908	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.3	+.2
Fixed Charge Cov. (%)	281	312	339

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	3.0%	3.0%	*4.0%*
"Cash Flow"	3.5%	4.0%	*7.0%*
Earnings	9.0%	10.0%	*6.5%*
Dividends	3.0%	14.0%	*13.5%*
Book Value	6.5%	7.0%	*3.5%*

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1396.2	842.5	821.9	1067.3	4127.9
2010	1248.6	890.9	973.2	1089.8	4202.5
2011	1328.7	991.7	1052.8	1113.2	4486.4
2012	1191.2	***933.8***	***975***	***1150***	***4250***
2013	***1350***	***1000***	***1000***	***1200***	***4550***

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.60	.27	.25	.48	1.60
2010	.55	.37	.47	.53	1.92
2011	.72	.41	.55	.49	2.18
2012	.74	***.42***	***.54***	***.55***	***2.25***
2013	***.80***	***.45***	***.56***	***.59***	***2.40***

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.135	.135	.135	.135	.54
2009	.169	.169	.169	.169	.68
2010	.20	.20	.20	.20	.80
2011	.26	.26	.26	.26	1.04
2012	.30	.30			

BUSINESS: Wisconsin Energy Corporation is a holding company for We Energies, which provides electric, gas & steam service in Wisconsin. Customers: 1.1 mill. elec., 1.1 mill. gas. Acq'd WICOR 4/00. Discontinued pump-manufacturing operations in '04. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 36%; small commercial & industrial, 31%; large commercial & industrial, 24%; other, 9%. Generating sources: coal, 54%; gas, 7%; hydro, 1%; wind, 1%; purchased, 37%. Fuel costs: 42% of revs. '11 reported deprec. rate (utility): 2.8%. Has 4,600 employees. Chairman, President & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

Wisconsin Energy's utility subsidiaries have filed a general rate case. The company is seeking electric rate increases of $172.6 million (6.2%) for 2013 and $37.4 million for 2014, a rate *decrease* of $17.1 million for 2013, and small rate hikes for steam service. The company is requesting the same 10.4%-10.5% allowed returns on equity that it currently has, and the staff of the Wisconsin commission has agreed not to contest the allowed ROE or the common-equity ratio. An order should come in time for new tariffs to take effect at the start of 2013.

A rate case is pending in Michigan, as well. The utility filed for a rate boost of $17.5 million (9.9%), based on a return on equity of 10.4%. In January, it self-implemented a rate increase of $7.7 million, as is allowable under Michigan regulatory law. The commission will issue its order in July, and new tariffs will take effect then.

We estimate that earnings will advance in 2012 and 2013. The utility postponed an electric rate hike that would have taken effect this year by suspending $140.1 million of regulatory amortization. Our 2012 earnings estimate is within management's targeted range of $2.24-$2.29 a share. Rate relief should help lift the bottom line next year. In addition, average shares outstanding are declining, thanks to a stock buyback. Through the end of the first quarter, Wisconsin Energy had $100 million remaining from a $300 million repurchase authorization.

Shareholders can expect hefty dividend hikes in 2013 and 2014. Wisconsin Energy wants to approach a 60% payout ratio by 2014, after more than a decade in which this figure was well below average for a utility. The board of directors raised the disbursement 15.4% earlier this year, and the company has suggested that increases of more than 10% are in the offing for each of the next two years.

In our view, Wisconsin Energy's strengths are reflected in the share price, which is up 8% so far in 2012. The low yield (for a utility) is typical for a company with substantial dividend-growth potential. With the quotation near the midpoint of our 3- to 5-year Target Price Range, total return prospects are modest.

Paul E. Debbas, CFA *June 22, 2012*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (5¢); '00, 10¢ net; '02, (44¢); '03, (10¢) net; '04, (42¢); gains on disc. ops.: '04, 77¢; '05, 2¢; '06, 2¢; '09, 2¢; '10, 1¢; '11, 6¢. '11 EPS don't add due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '11: $7.29/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates allowed on com. eq. in '10: 10.4%-10.5%; earned on avg. com. eq., '11: 13.1%. Regulatory Climate: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	95

XCEL ENERGY NYSE-XEL

RECENT PRICE	26.71	P/E RATIO	15.8 (Trailing: 15.9 / Median: 14.0)	RELATIVE P/E RATIO	1.03	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS 3 Lowered 2/17/12

SAFETY 2 Raised 5/14/04

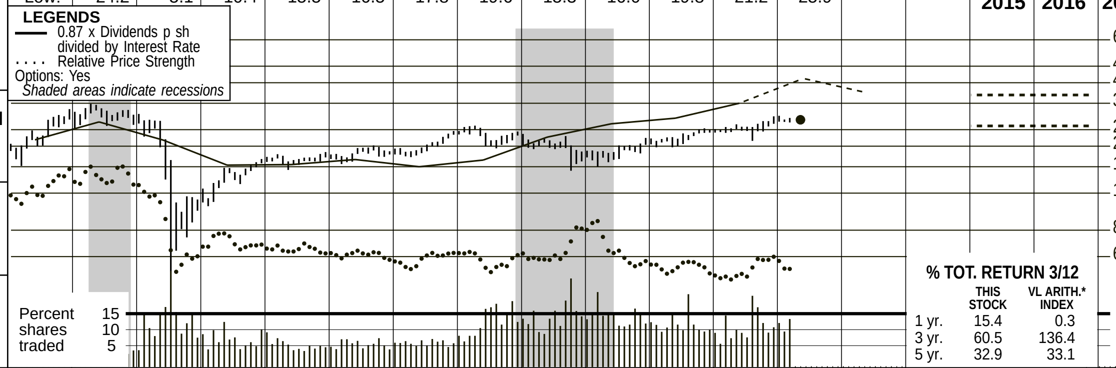
TECHNICAL 4 Lowered 3/30/12

BETA .65 (1.00 = Market)

High:	31.8	28.5	17.4	18.8	20.2	23.6	25.0	22.9	21.9	24.4	27.8	27.9
Low:	24.2	5.1	10.4	15.5	16.5	17.8	19.6	15.3	16.0	19.8	21.2	25.9

Target Price Range 2015 | 2016 | 2017

LEGENDS
0.87 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+30%)	10%
Low	25	(-5%)	3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	1	0	0	0	0	0	2
Options	0	0	0	0	0	5	1	0	0
to Sell	0	0	0	0	0	5	1	0	0

Institutional Decisions

	2Q2011	3Q2011	4Q2011
to Buy	199	206	218
to Sell	166	164	171
Hld's(000)	289658	296827	298171

% TOT. RETURN 3/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.4	0.3
3 yr.	60.5	136.4
5 yr.	32.9	33.1

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
19.22	18.32	18.46	18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	21.35	22.20	Revenues per sh	25.25
4.33	3.92	4.30	4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	3.95	4.10	"Cash Flow" per sh	4.75
1.91	1.61	1.84	1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.75	1.85	Earnings per sh A	2.25
1.37	1.40	1.43	1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.06	1.11	Div'd Decl'd per sh B ■	1.35
2.99	2.90	2.99	13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.40	6.50	Cap'l Spending per sh	4.75
15.46	15.89	16.25	16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.15	19.25	Book Value per sh C	21.75
138.13	149.24	152.70	155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	490.00	507.00	Common Shs Outst'g D	515.00
12.5	15.5	15.2	16.6	14.3	12.4	40.8	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	Bold figures are		Avg Ann'l P/E Ratio	13.0
.78	.89	.79	.95	.93	.64	2.23	.66	.72	.82	.80	.89	.82	.85	.90	.90	Value Line		Relative P/E Ratio	.85
5.7%	5.6%	5.1%	6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	estimates		Avg Ann'l Div'd Yield	4.7%

CAPITAL STRUCTURE as of 12/31/11
Total Debt $9962.6 mill. **Due in 5 Yrs** $1962.4 mill.
LT Debt $9450.2 mill. **LT Interest** $599.5 mill.
Incl. $191.4 mill. capitalized leases.
(LT interest earned: 3.1x)

Leases, Uncapitalized Annual rentals $185.6 mill.
Pension Assets-12/11 $2.67 bill. **Oblig.** $3.23 bill.

Pfd Stock None

Common Stock 486,828,501 shs.
as of 2/21/12
MARKET CAP: $13 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
9524.4	7937.5	8345.3	9625.5	9840.3	10034	11203	9644.3	10311	10655	10450	11250	Revenues ($mill)	13000
177.6	510.0	526.9	499.0	568.7	575.9	645.7	685.5	727.0	841.4	855	930	Net Profit ($mill)	1110
32.7%	23.7%	23.2%	25.8%	24.2%	33.8%	34.4%	35.1%	37.5%	35.8%	35.0%	35.0%	Income Tax Rate	35.0%
46.7%	8.9%	10.9%	8.5%	9.8%	12.5%	15.9%	16.8%	11.7%	9.4%	12.0%	12.0%	AFUDC % to Net Profit	8.0%
59.6%	55.3%	55.0%	51.7%	52.1%	49.7%	52.2%	51.6%	53.1%	51.1%	53.5%	52.5%	Long-Term Debt Ratio	50.0%
39.5%	43.8%	44.1%	47.3%	47.0%	49.4%	47.1%	47.7%	46.3%	48.9%	46.5%	47.5%	Common Equity Ratio	50.0%
11815	11790	11801	11398	12371	12748	14800	15277	17452	17331	19250	20550	Total Capital ($mill)	22400
18816	13667	14096	14696	15549	16676	17689	18508	20663	22353	23925	26100	Net Plant ($mill)	29700
5.4%	6.1%	6.2%	6.2%	6.2%	6.3%	6.0%	6.2%	5.7%	6.5%	6.0%	6.0%	Return on Total Cap'l	6.5%
3.7%	9.7%	9.9%	9.1%	9.6%	9.0%	9.1%	9.3%	8.9%	9.9%	9.5%	9.5%	Return on Shr. Equity	10.0%
3.7%	9.8%	10.0%	9.2%	9.7%	9.1%	9.2%	9.4%	8.9%	9.9%	9.5%	9.5%	Return on Com Equity E	10.0%
NMF	3.9%	3.9%	2.9%	3.6%	3.1%	3.8%	3.7%	3.6%	4.3%	4.0%	4.0%	Retained to Com Eq	3.5%
NMF	60%	62%	69%	63%	66%	59%	61%	59%	56%	61%	60%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-3.0	+3.0	+.4
Large C & I Use (MWH)	24225	24431	24286
Large C & I Revs. per KWH (¢)	5.34	5.65	5.90
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21108	20517	21898
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	- -	+.4
Fixed Charge Cov. (%)	258	277	298

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-4.0%	-1.5%	3.0%
"Cash Flow"	-2.0%	1.0%	5.0%
Earnings	-1.0%	4.5%	6.0%
Dividends	-4.0%	3.5%	5.0%
Book Value	- -	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2695	2016	2315	2618	9644.3
2010	2807	2308	2629	2567	10311
2011	2817	2438	2832	2568	10655
2012	2578	2422	2850	2600	10450
2013	2900	2650	3000	2700	11250

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.38	.25	.48	.37	1.49
2010	.36	.29	.62	.29	1.56
2011	.42	.33	.69	.28	1.72
2012	.38	.34	.69	.34	1.75
2013	.42	.36	.71	.36	1.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.23	.23	.2375	.2375	.94
2009	.2375	.2375	.245	.245	.97
2010	.245	.245	.2525	.2525	1.00
2011	.2525	.2525	.26	.26	1.03
2012	.26	.26			

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota, & Michigan & gas to Minnesota, Wisconsin, North Dakota, & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.4 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 31%; sm. commercial & industrial, 35%; lg. commercial & industrial, 18%; other, 16%. Generating sources not avail. Fuel costs: 48% of revs. '11 reported depr. rate: 2.9%. Has 11,300 empls. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Web: www.xcelenergy.com.

Xcel Energy's Colorado utility had mixed results in its rate case. Public Service of Colorado filed for an electric rate increase of $141.9 million, including an interim tariff hike of $100 million. The Colorado Public Utilities Commission (CPUC) rejected the utility's request for interim rate relief, but P.S. of Colorado was still able to reach a regulatory settlement with the CPUC staff and various intervenors. The agreement, which awaits a decision by the CPUC, calls for a rate hike of $73 million (effective May 1, 2012), followed by boosts of $16 million and $25 million at the start of 2013 and 2014, respectively. The raises are based on a 10% return on a 56% common-equity ratio.

The company has rate cases in other states, as well. In Minnesota, the state commission approved a settlement for Northern States Power, which provided for a $14.8 million rate hike this year. NSP plans to file another rate application later this year. The utility is awaiting a final order in its South Dakota rate case, in which it sought a $14.6 million increase. An interim rate hike of $12.7 million took effect at the start of 2012.

We have lowered our 2012 share-earnings estimate by a dime, to $1.75. The lack of interim rate relief in Colorado hurt earnings in the first quarter. An unusually mild winter reduced profits by $0.05 a share, as well. Accordingly, management now expects earnings to wind up in the lower half of its previously stated target of $1.75-$1.85 a share for 2012. Even the low end of the company's guidance would still produce a slight earnings increase from the 2011 tally, however.

We expect a dividend increase at the board meeting in May. We look for the directors to boost the annual payout by $0.03 a share (2.9%), the same increase as in recent years.

Stronger earnings growth is probable in 2013. Xcel should benefit from rate relief, especially in Colorado. Also, we assume a return to normal weather patterns in the first quarter. Our forecast of $1.85 a share would produce bottom-line growth within Xcel's goal of 5%-7% annually.

This stock has a yield and 3- to 5-year total return potential that are about average, by utility standards.

Paul E. Debbas, CFA *May 4, 2012*

(A) Diluted EPS. Excl. nonrec. gain (loss): '02, ($6.27); '10, 5¢; gains (losses) on disc. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '09 EPS don't add due to rounding. Next egs. report due late Jul. **(B)** Div'ds histor. paid mid-Jan., Apr., July and Oct. ■ Div'd reinvestment plan avail. **(C)** Incl. intang. In '11: $4.91/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Varies. Rate all'd on com. eq.: MN '09 10.88%; WI '08 10.75%; CO '10 (elec.) 10.5%; CO '07 (gas) 10.25%; TX '86 15.05%; earned on avg. com. eq., '11: 10.1%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	100

Attachment 23c

REFER TO LIVE SPREADSHEET

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 24a

REFER TO LIVE SPREADSHEET

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(accessible by opening the Attachments Tab in Adobe)

Attachment 24b

<HELP> for explanation, <MENU> for similar functions. Equity EEO

#<Go> to view details

GAS US Equity 95) Actions 96) Alert BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	2.739	-0.190	8(8)	2.994	-0.065	8(8)
2) EPS GAAP	2.647	-0.128	3(3)	2.933	-0.107	3(3)
3) Cash Flow Per Share	6.303	-0.242	3(3)	7.060	0.140	3(3)
4) Dividends Per Share	1.890	-0.010	6(6)	1.880	0.008	6(6)
5) Book Value Per Share	29.160	3.750	1(1)	29.990	3.570	1(1)
6) Sales	4532.000	416.000	4(4)	4799.000	591.667	4(4)
7) EBITDA	1105.600	8.600	5(5)	1176.800	11.300	5(5)
8) EBIT	695.667	-39.833	3(3)	755.333	-29.667	3(3)
9) Operating Profit	310.250	106.583	4(4)	359.250	112.917	4(4)
10) Pre-Tax Profit	510.750	-23.583	4(4)	568.500	-19.500	4(4)
11) Net Income Adjusted+	313.750	-13.250	4(4)	349.000	-11.333	4(4)
12) Net Income GAAP	311.000	-15.500	3(3)	345.333	-12.167	3(3)
13) Long Term Growth	4.000	0.000	1(1)			
14) Return on Equity	7.085	-0.080	2(2)	10.700	0.000	1(1)
15) Return on Assets						

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	13.742	12.572	Price/Cash Flow	5.971	5.331
Price/Sales	.974	.92	Dividend Yield	5.021	4.995
Price/Book	1.291	1.255	EV/EBITDA	7.771	7.301

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LNT US Equity | 95) Actions | 96) Alert | BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	2.843	-0.083	10(10)	3.108	-0.069	10(10)
2) EPS GAAP	2.812	-0.138	5(5)	3.086	-0.044	5(5)
3) Cash Flow Per Share	6.415	-0.305	2(2)	6.675	0.235	2(2)
4) Dividends Per Share	1.792	0.002	6(6)	1.878	-0.013	6(6)
5) Book Value Per Share	27.443	-0.257	3(3)	28.647	-0.650	3(3)
6) Sales	3286.250	-110.125	8(8)	3443.250	-76.607	8(8)
7) EBITDA	855.429	-27.857	7(7)	966.143	-41.024	7(7)
8) EBIT	520.600	-30.600	5(5)	616.000	-47.250	5(5)
9) Operating Profit	500.750	-46.500	4(4)	571.000	-61.250	4(4)
10) Pre-Tax Profit	390.400	-24.800	5(5)	471.200	-46.050	5(5)
11) Net Income Adjusted+	315.167	-14.833	6(6)	349.000	-14.833	6(6)
12) Net Income GAAP	312.333	-20.000	3(3)	347.000	-17.500	3(3)
13) Long Term Growth	5.750	0.000	4(4)			
14) Return on Equity	9.755	-0.295	4(4)	10.513	-0.147	3(3)
15) Return on Assets	3.603	-0.287	3(3)	4.113	-0.517	3(3)

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	15.709	14.369	Price/Cash Flow	6.962	6.691
Price/Sales	1.508	1.439	Dividend Yield	4.013	4.205
Price/Book	1.627	1.559	EV/EBITDA	9.256	8.196

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ATO US Equity | 95) Actions | 96) Alert | BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	09/2012 Yr	4Wk Chg	# Est.	09/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	2.303	-0.025	8(8)	2.484	-0.004	8(8)
2) EPS GAAP	2.313	0.003	4(4)	2.450	0.023	4(4)
3) Cash Flow Per Share	5.365	0.815	2(2)	5.560	-0.030	2(2)
4) Dividends Per Share	1.380	0.000	5(5)	1.408	-0.002	6(6)
5) Book Value Per Share	24.990	-1.130	2(2)	27.630	0.480	2(2)
6) Sales	4035.250	-242.500	4(4)	4096.500	-328.000	4(4)
7) EBITDA	729.000	-4.500	5(5)	772.600	-7.150	5(5)
8) EBIT	475.500	-12.500	2(2)	511.500	-12.000	2(2)
9) Operating Profit	481.750	-5.917	4(4)	518.250	-8.750	4(4)
10) Pre-Tax Profit	335.000	0.000	4(4)	358.250	-0.083	4(4)
11) Net Income Adjusted+	207.000	-1.667	4(4)	224.000	1.000	4(4)
12) Net Income GAAP	208.000	-0.500	3(3)	222.667	2.167	3(3)
13) Long Term Growth	6.000	0.000	1(1)			
14) Return on Equity	9.255	0.135	2(2)	9.900	0.000	1(1)
15) Return on Assets						

Valuation Measure	09/2012 Yr	09/2013 Yr	Valuation Measure	09/2012 Yr	09/2013 Yr
Price/EPS Adjusted	14.221	13.184	Price/Cash Flow	6.104	5.89
Price/Sales	.731	.72	Dividend Yield	4.214	4.299
Price/Book	1.311	1.185	EV/EBITDA	7.245	6.836

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ED US Equity | 95) Actions | 96) Alert | BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	3.746	-0.002	17(17)	3.849	0.007	15(15)
2) EPS GAAP	3.733	-0.019	4(4)	3.843	-0.004	4(4)
3) Cash Flow Per Share	7.567	-0.103	3(3)	7.483	0.133	3(3)
4) Dividends Per Share	2.420	0.000	8(8)	2.449	0.002	8(8)
5) Book Value Per Share	40.624	-0.306	5(5)	42.038	-0.260	4(4)
6) Sales	13440.556	-340.611	10(9)	13761.429	-513.571	8(7)
7) EBITDA	3263.875	-35.943	8(8)	3387.571	-30.729	7(7)
8) EBIT	2340.200	-20.550	5(5)	2399.000	-24.143	4(4)
9) Operating Profit	2321.125	-25.693	8(8)	2406.000	-16.000	8(8)
10) Pre-Tax Profit	1741.000	2.727	8(8)	1790.375	-0.170	8(8)
11) Net Income Adjusted+	1103.000	-2.800	8(8)	1136.750	-4.550	8(8)
12) Net Income GAAP	1105.750	-2.107	4(4)	1135.750	-10.250	4(4)
13) Long Term Growth	3.350	-0.567	2(2)			
14) Return on Equity	9.420	0.038	5(4)	9.390	0.110	3(3)
15) Return on Assets	2.780	-0.220	1(1)	2.800	-0.200	1(1)

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	15.638	15.22	Price/Cash Flow	7.742	7.828
Price/Sales	1.277	1.247	Dividend Yield	4.131	4.181
Price/Book	1.442	1.394	EV/EBITDA	8.414	8.107

<HELP> for explanation. Equity EEO
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TEG US Equity | 95) Actions | 96) Alert | BEst Consensus Overview

Consensus ■Standard ■28 Days ■Post Event ■Custom ■In-House

Period 2012* - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	3.450	-0.043	7(7)	3.647	0.008	6(6)
2) EPS GAAP	3.150	-0.260	1(1)	3.600	NA	1(1)
3) Cash Flow Per Share	6.630	-0.010	1(1)	6.940	-0.010	1(1)
4) Dividends Per Share	2.720	0.000	4(4)	2.730	0.000	4(4)
5) Book Value Per Share	38.690	-0.010	1(1)	39.860	-0.010	1(1)
6) Sales	4694.750	-368.750	4(4)	4849.667	-479.333	3(3)
7) EBITDA	746.750	-16.750	4(4)	804.500	-1.500	4(4)
8) EBIT						
9) Operating Profit	443.333	-30.333	3(3)	499.333	-3.333	3(3)
10) Pre-Tax Profit	396.000	-40.500	3(3)	446.667	-10.333	3(3)
11) Net Income Adjusted+	267.667	-11.000	3(3)	293.333	0.000	3(3)
12) Net Income GAAP	252.000	-27.500	1(1)	292.000	-1.000	1(1)
13) Long Term Growth	4.300	-0.200	3(3)			
14) Return on Equity	9.133	0.000	3(3)	9.500	0.050	2(2)
15) Return on Assets	2.700	0.000	1(1)	2.800	0.100	1(1)

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	15.603	14.76	Price/Cash Flow	8.119	7.756
Price/Sales	.898	.869	Dividend Yield	5.053	5.072
Price/Book	1.391	1.35	EV/EBITDA	8.906	8.267

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NWN US Equity | 95) Actions | 96) Alert | BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012 - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	2.509	-0.050	7(7)	2.697	-0.010	7(7)
2) EPS GAAP	2.500	-0.036	6(6)	2.682	0.012	6(6)
3) Cash Flow Per Share	5.325	-0.075	2(2)	5.500	-0.010	2(2)
4) Dividends Per Share	1.797	-0.002	6(6)	1.850	-0.010	6(6)
5) Book Value Per Share	28.025	0.660	2(2)	26.890	-0.465	2(2)
6) Sales	851.000	-15.250	4(4)	870.250	-23.750	4(4)
7) EBITDA	234.500	0.071	6(6)	241.800	-0.533	5(5)
8) EBIT	155.000	-2.000	2(2)	161.000	-1.667	2(2)
9) Operating Profit	153.800	-1.033	5(5)	161.200	-1.133	5(5)
10) Pre-Tax Profit	112.600	-1.067	5(5)	120.400	0.400	5(5)
11) Net Income Adjusted+	66.880	-0.837	5(5)	71.540	-0.310	5(5)
12) Net Income GAAP	67.033	-0.967	3(3)	70.467	-0.458	3(3)
13) Long Term Growth	3.375	-0.250	4(4)			
14) Return on Equity	9.228	-0.250	4(4)	9.700	-0.067	3(3)
15) Return on Assets	2.400	0.000	1(1)	2.600	0.000	1(1)

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	18.238	16.967	Price/Cash Flow	8.593	8.32
Price/Sales	1.441	1.409	Dividend Yield	3.927	4.043
Price/Book	1.633	1.702	EV/EBITDA	8.434	8.179

<HELP> for explanation. Equity EEO

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PNY US Equity 95) Actions 96) Alert BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	10/2012 Yr	4Wk Chg	# Est.	10/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	1.598	0.008	6(6)	1.748	0.000	5(5)
2) EPS GAAP	1.593	0.009	4(4)	1.730	-0.005	3(3)
3) Cash Flow Per Share	-0.350	0.000	1(1)	3.010	0.000	1(1)
4) Dividends Per Share	1.190	-0.002	4(4)	1.230	-0.002	4(4)
5) Book Value Per Share	18.720	0.000	1(1)	17.780	0.000	1(1)
6) Sales	1277.000	-14.333	2(2)	1345.000	-18.333	2(2)
7) EBITDA	334.000	4.750	3(3)	370.667	5.167	3(3)
8) EBIT	137.000	-36.000	1(1)	181.000	-28.500	1(1)
9) Operating Profit	140.000	-23.000	2(2)	171.000	-22.333	2(2)
10) Pre-Tax Profit	114.000	-31.500	1(1)	127.000	-37.000	1(1)
11) Net Income Adjusted+	114.000	0.333	2(2)	122.500	-1.500	2(2)
12) Net Income GAAP	114.000	0.000	2(2)	122.500	0.000	2(2)
13) Long Term Growth	4.000	0.000	2(2)			
14) Return on Equity	11.370	-0.350	2(2)			
15) Return on Assets						

Valuation Measure	10/2012 Yr	10/2013 Yr	Valuation Measure	10/2012 Yr	10/2013 Yr
Price/EPS Adjusted	18.63	17.031	Price/Cash Flow	N.A.	9.89
Price/Sales	1.671	1.587	Dividend Yield	3.997	4.132
Price/Book	1.59	1.674	EV/EBITDA	9.75	8.785

<HELP> for explanation. Equity EEO
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SO US Equity | 95) Actions | 96) Alert | BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	2.650	-0.016	20(20)	2.814	-0.005	18(18)
2) EPS GAAP	2.655	-0.004	12(12)	2.811	-0.003	11(11)
3) Cash Flow Per Share	5.420	-0.035	4(4)	5.168	-0.028	4(4)
4) Dividends Per Share	1.947	-0.003	10(9)	2.013	-0.003	10(9)
5) Book Value Per Share	22.473	0.003	4(4)	23.533	-0.245	4(4)
6) Sales	18391.385	-239.687	13(13)	19219.750	-172.833	12(12)
7) EBITDA	6245.500	-21.577	12(12)	6659.417	12.083	12(12)
8) EBIT	4486.625	58.625	8(8)	4795.125	-32.589	8(8)
9) Operating Profit	4393.667	-57.333	9(9)	4717.222	-39.444	9(9)
10) Pre-Tax Profit	3567.545	-17.000	11(11)	3842.818	-9.000	11(11)
11) Net Income Adjusted+	2318.333	-8.083	12(12)	2498.917	1.083	12(12)
12) Net Income GAAP	2338.833	12.833	6(6)	2504.167	9.367	6(6)
13) Long Term Growth	5.667	-0.293	3(3)			
14) Return on Equity	12.203	-0.217	6(6)	12.215	-0.079	4(4)
15) Return on Assets	5.565	0.000	2(2)	5.715	0.060	2(2)

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	17.094	16.098	Price/Cash Flow	8.358	8.766
Price/Sales	2.14	2.047	Dividend Yield	4.298	4.444
Price/Book	2.016	1.925	EV/EBITDA	9.823	9.213

<HELP> for explanation. EquityEEO
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VVC US Equity | 95) Actions | 96) Alert | BEst Consensus Overview

Consensus ■Standard ■28 Days ■Post Event ■Custom ■In-House

Period 2012* - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	1.860	-0.005	6(6)	1.962	-0.008	5(5)
2) EPS GAAP	1.868	0.000	4(4)	1.993	0.000	3(3)
3) Cash Flow Per Share	5.315	0.005	2(2)	5.450	0.000	1(1)
4) Dividends Per Share	1.412	-0.002	5(5)	1.430	-0.006	5(5)
5) Book Value Per Share	18.380	-0.090	1(1)	18.990	-0.070	1(1)
6) Sales	2424.250	8.750	4(4)	2553.000	4.333	3(3)
7) EBITDA	584.500	0.000	2(2)	607.500	0.000	2(2)
8) EBIT	361.000	0.500	2(2)	375.500	0.000	2(2)
9) Operating Profit	368.667	-0.333	3(3)	373.333	-0.333	3(3)
10) Pre-Tax Profit	234.500	0.000	2(2)	251.000	0.500	2(2)
11) Net Income Adjusted+	153.000	0.333	3(3)	163.667	-0.333	3(3)
12) Net Income GAAP	150.000	0.000	1(1)	163.000	0.000	1(1)
13) Long Term Growth	5.567	0.033	3(3)			
14) Return on Equity	10.267	0.033	3(3)	10.700	0.000	2(2)
15) Return on Assets						

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	15.613	14.801	Price/Cash Flow	5.464	5.328
Price/Sales	.982	.933	Dividend Yield	4.862	4.924
Price/Book	1.58	1.529	EV/EBITDA	7.121	6.852

<HELP> for explanation. EquityEEO
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WGL US Equity 95) Actions 96) Alert BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	09/2012 Yr	4Wk Chg	# Est.	09/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	2.476	-0.061	7(7)	2.566	-0.063	7(7)
2) EPS GAAP	2.445	-0.062	4(4)	2.632	-0.040	5(5)
3) Cash Flow Per Share	3.060	-0.085	2(2)	4.405	-0.075	2(2)
4) Dividends Per Share	1.592	0.002	5(5)	1.666	0.018	5(5)
5) Book Value Per Share	24.180	-0.300	1(1)	25.290	-0.430	1(1)
6) Sales	2650.500	-133.500	4(4)	2795.750	-141.650	4(4)
7) EBITDA	359.800	-0.367	5(5)	375.750	-1.650	4(4)
8) EBIT	254.500	-4.167	2(2)	271.500	-5.167	2(2)
9) Operating Profit	250.800	-7.700	5(5)	273.400	-3.600	5(5)
10) Pre-Tax Profit	209.400	-6.600	5(5)	226.400	-4.100	5(5)
11) Net Income Adjusted+	124.800	-6.700	5(5)	135.200	-2.300	5(5)
12) Net Income GAAP	120.667	-6.833	3(3)	134.667	-3.833	3(3)
13) Long Term Growth	5.500	0.000	1(1)			
14) Return on Equity	10.100	0.000	1(1)			
15) Return on Assets						

Valuation Measure	09/2012 Yr	09/2013 Yr	Valuation Measure	09/2012 Yr	09/2013 Yr
Price/EPS Adjusted	15.59	15.043	Price/Cash Flow	12.614	8.763
Price/Sales	.751	.712	Dividend Yield	4.124	4.316
Price/Book	1.596	1.526	EV/EBITDA	7.401	7.087

<HELP> for explanation, <MENU> for similar functions. EquityEEO

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WEC US Equity | 95) Actions | 96) Alert | BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	2.275	0.003	15(15)	2.386	0.000	14(14)
2) EPS GAAP	2.276	0.010	7(7)	2.394	-0.002	7(7)
3) Cash Flow Per Share	4.165	0.220	2(2)	4.225	0.395	2(2)
4) Dividends Per Share	1.200	0.003	7(7)	1.337	-0.003	7(7)
5) Book Value Per Share	18.252	-0.036	5(5)	19.350	0.170	5(5)
6) Sales	4622.300	67.856	10(10)	4804.800	61.800	10(10)
7) EBITDA	1348.300	-14.367	10(10)	1403.800	17.657	10(10)
8) EBIT	1022.000	5.200	6(6)	1052.167	30.500	6(6)
9) Operating Profit	966.333	-9.417	6(6)	1008.833	-5.667	6(6)
10) Pre-Tax Profit	804.429	6.029	7(7)	836.000	3.500	7(7)
11) Net Income Adjusted+	525.556	-0.016	9(9)	544.222	-1.778	9(9)
12) Net Income GAAP	521.400	-1.267	5(5)	540.200	-3.300	5(5)
13) Long Term Growth	4.500	-3.000	2(2)			
14) Return on Equity	12.243	0.609	4(4)	12.200	0.667	3(3)
15) Return on Assets	3.850	0.050	2(2)	3.850	0.050	2(2)

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	16.343	15.583	Price/Cash Flow	8.927	8.8
Price/Sales	1.854	1.783	Dividend Yield	3.228	3.596
Price/Book	2.037	1.921	EV/EBITDA	10.216	9.812

<HELP> for explanation, <MENU> for similar functions. Equity **EEO**

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XEL US Equity 95) Actions 96) Alert BEst Consensus Overview

Consensus Standard 28 Days Post Event Custom In-House

Period 2012* - Yr Cur USD

Measure	12/2012 Yr	4Wk Chg	# Est.	12/2013 Yr	4Wk Chg	# Est.
1) EPS Adjusted+	1.777	-0.007	15(15)	1.883	-0.004	13(13)
2) EPS GAAP	1.776	-0.007	10(10)	1.886	0.001	9(9)
3) Cash Flow Per Share	5.073	-0.108	4(4)	4.323	-0.127	3(3)
4) Dividends Per Share	1.064	0.003	10(10)	1.101	0.002	10(10)
5) Book Value Per Share	18.236	-0.437	5(5)	19.378	-0.458	4(4)
6) Sales	10938.182	-180.152	11(11)	11318.909	-236.727	11(11)
7) EBITDA	2805.455	7.182	11(11)	2996.900	31.344	10(10)
8) EBIT	1920.200	34.771	5(5)	2029.400	17.400	5(5)
9) Operating Profit	1864.556	44.931	9(9)	2003.000	55.625	9(9)
10) Pre-Tax Profit	1332.500	-7.227	10(10)	1442.700	-2.900	10(10)
11) Net Income Adjusted+	866.364	-1.386	11(11)	935.182	-0.273	11(11)
12) Net Income GAAP	865.375	-1.482	8(8)	935.875	2.708	8(8)
13) Long Term Growth	4.580	-0.687	5(5)			
14) Return on Equity	9.935	0.193	11(11)	10.053	0.217	9(9)
15) Return on Assets	3.957	1.087	3(3)	3.980	1.025	3(3)

Valuation Measure	12/2012 Yr	12/2013 Yr	Valuation Measure	12/2012 Yr	12/2013 Yr
Price/EPS Adjusted	15.352	14.488	Price/Cash Flow	5.378	6.31
Price/Sales	1.214	1.174	Dividend Yield	3.9	4.036
Price/Book	1.496	1.408	EV/EBITDA	8.352	7.818

Analysts:

AGL Resources Inc (GAS.N)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - NATURAL GAS

OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

GAS.N on New York Stock Exchange

39.21USD
3:08pm EDT

Price Change (% chg)
$0.53(+1.37%)

Prev Close $38.68	Day's High $39.32	Volume 77,427	52-wk High $43.69
Open $38.69	Day's Low $38.64	Avg. Vol 497,813	52-wk Low $34.08

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.28	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	1	1	1	1
(2) OUTPERFORM	1	1	1	1
(3) HOLD	8	8	7	7
(4) UNDERPERFORM	0	0	1	1
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.70	2.70	2.80	2.80

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	1.16
Q4	0.87

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	4	879.84	1,029.36	743.00	--
Quarter Ending Sep-12	3	727.78	937.16	603.18	--
Year Ending Dec-12	5	4,623.98	5,248.10	4,025.17	2,584.34
Year Ending Dec-13	5	4,883.71	5,366.48	4,381.00	2,657.54
Earnings (per share)					
Quarter Ending Jun-12	7	0.28	0.39	0.16	--
Quarter Ending Sep-12	6	0.19	0.32	0.07	--
Year Ending Dec-12	8	2.69	2.90	2.55	3.29
Year Ending Dec-13	8	2.99	3.05	2.72	3.41
LT Growth Rate (%)	4	4.43	7.00	2.60	5.37

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	1,442.69	1,404.00	38.69	2.68
Quarter Ending Dec-11	845.53	790.00	55.53	6.57
Quarter Ending Sep-11	376.43	295.00	81.43	21.63
Quarter Ending Jun-11	423.36	375.00	48.36	11.42
Quarter Ending Mar-11	1,066.27	878.00	188.27	17.66
Earnings (per share)				
Quarter Ending Mar-12	1.31	1.16	0.15	11.34
Quarter Ending Dec-11	0.92	0.87	0.05	5.84
Quarter Ending Sep-11	0.14	0.02	0.12	85.89
Quarter Ending Jun-11	0.28	0.33	0.05	18.71
Quarter Ending Mar-11	1.62	1.63	0.01	0.37

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	879.84	879.84	879.84	867.24	--
Quarter Ending Sep-12	727.78	727.78	727.78	761.47	--
Year Ending Dec-12	4,623.98	4,623.98	4,623.98	4,335.06	2,584.34
Year Ending Dec-13	4,883.71	4,883.71	4,883.71	4,461.09	2,657.54
Earnings (per share)					
Quarter Ending Jun-12	0.28	0.28	0.28	0.31	--
Quarter Ending Sep-12	0.19	0.19	0.19	0.16	--
Quarter Ending Dec-12	2.69	2.69	2.74	2.87	3.29
Quarter Ending Dec-13	2.99	2.99	2.99	3.09	3.41

Q3	**0.02**
Q2	**0.33**
Q1	**1.63**
Future Estimates	
Q1 12	**0.16**
Q4 12	**0.07**

» More Financials

AGL RESOURCES INC NEWS

» More GAS.N News

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
NICOR INC (GAS) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	**$25.00** BUY
ValuEngine Industry Report for Utility-gas Distribution Provider: ValuEngine, Inc.	**$196.00** BUY
Trading Report for (GAS). A detailed report, including free correlated market analysis, and updates. Provider: Stock Traders Daily	**$58.00** BUY
The Investment Rate - a measure of investment demand. Provider: Stock Traders Daily	**$495.00** BUY
Thomson Reuters Stock Report - AGL RESOURCES INC. (GAS-N) Provider: Thomson Reuters Stock Report	**$25.00** BUY

» More Analyst Research

Analysts:

Alliant Energy Corp (LNT.N)

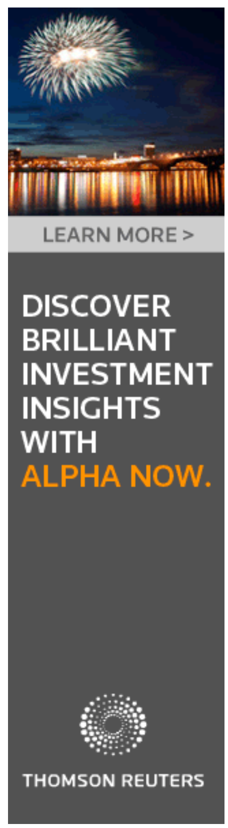
LNT.N on New York Stock Exchange

45.64USD
3:07pm EDT

Price Change (% chg)
$-0.17(-0.37%)

Prev Close	Day's High	Volume	52-wk High
$45.81	$45.99	56,030	$45.91

Open	Day's Low	Avg. Vol	52-wk Low
$45.89	$45.63	501,389	$33.91



CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Outperform	0.44	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	4	4	4	4
(2) OUTPERFORM	2	2	3	2
(3) HOLD	5	5	4	5
(4) UNDERPERFORM	0	0	0	0
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.09	2.09	2.00	2.09

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.5
Q4	0.51

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	3	680.78	786.00	568.33	581.31
Quarter Ending Sep-12	3	1,003.45	1,262.94	850.40	1,708.76
Year Ending Dec-12	9	3,281.69	3,607.00	3,073.20	3,683.25
Year Ending Dec-13	9	3,432.36	3,770.00	3,284.90	3,798.12
Earnings (per share)					
Quarter Ending Jun-12	5	0.44	0.47	0.40	0.32
Quarter Ending Sep-12	5	1.31	1.38	1.25	1.75
Year Ending Dec-12	11	2.84	3.00	2.75	2.97
Year Ending Dec-13	11	3.11	3.20	3.00	3.14
LT Growth Rate (%)	5	5.92	6.60	5.00	5.93

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	822.13	765.70	56.43	6.86
Quarter Ending Dec-11	728.93	879.20	150.27	20.61
Quarter Ending Sep-11	1,111.45	1,021.60	89.85	8.08
Quarter Ending Jun-11	768.14	819.50	51.36	6.69
Quarter Ending Mar-11	858.33	945.00	86.67	10.10
Earnings (per share)				
Quarter Ending Mar-12	0.63	0.50	0.13	20.92
Quarter Ending Dec-11	0.53	0.51	0.02	4.19
Quarter Ending Sep-11	1.32	1.12	0.20	15.09
Quarter Ending Jun-11	0.47	0.44	0.03	6.34
Quarter Ending Mar-11	0.52	0.68	0.16	30.27

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	680.78	680.78	680.78	681.97	581.31
Quarter Ending Sep-12	1,003.45	1,003.45	1,003.45	1,045.26	1,708.76
Year Ending Dec-12	3,281.69	3,281.69	3,281.69	3,426.68	3,683.25
Year Ending Dec-13	3,432.36	3,432.36	3,432.36	3,519.80	3,798.12
Earnings (per share)					
Quarter Ending Jun-12	0.44	0.44	0.44	0.40	0.32
Quarter Ending Sep-12	1.31	1.31	1.31	1.33	1.75
Quarter Ending Dec-12	2.84	2.84	2.84	2.93	2.97
Quarter Ending Dec-13	3.11	3.10	3.10	3.18	3.14

Q3	**1.12**
Q2	**0.44**
Q1	**0.68**
Future Estimates	
Q1 12	**0.404**
Q4 12	**1.25**

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ALLIANT ENERGY CORP NEWS

Alliant unit buys Wisconsin power plant from Calpine

» More LNT.N News

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
INTERSTATE ENERGY CORP (LNT) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	**$25.00** BUY
Trading Report for (LNT). A detailed report, including free correlated market analysis, and updates. Provider: Stock Traders Daily	**$58.00** BUY
The Investment Rate - a measure of investment demand. Provider: Stock Traders Daily	**$495.00** BUY
Thomson Reuters Stock Report - ALLIANT ENERGY CORPORATION (LNT-N) Provider: Thomson Reuters Stock Report	**$25.00** BUY
ValuEngine Detailed Valuation Report for LNT Provider: ValuEngine, Inc.	**$127.00** BUY

» More Analyst Research

Analysts:

Atmos Energy Corp (ATO.N)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - NATURAL GAS

OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

ATO.N on New York Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
34.60USD 3:12pm EDT	$0.06(+0.17%)	$34.54	$34.76	67,274	$35.55
		Open	Day's Low	Avg. Vol	52-wk Low
		$34.64	$34.38	324,536	$28.51

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.16	September	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	1	1	0	0
(2) OUTPERFORM	1	1	1	1
(3) HOLD	7	7	8	7
(4) UNDERPERFORM	0	0	0	1
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.67	2.67	2.89	3.00

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

EARNINGS VS. ESTIMATES

Last Five Estimates

Q2	1.28
Q1	0.61
Q4	0.08
Q3	0.04
Q2	1.35

Future Estimates

Q2 12	0.13
Q1 12	0.05

» More Financials

ATMOS ENERGY CORP NEWS

TEXT-Fitch affirms Atmos Energy ratings

» More ATO.N News

SALES (in millions)					
Quarter Ending Jun-12	4	847.55	918.56	773.54	866.78
Quarter Ending Sep-12	3	763.64	803.20	733.32	769.37
Year Ending Sep-12	5	4,055.41	4,481.00	3,863.90	5,067.51
Year Ending Sep-13	5	4,127.64	4,603.00	3,626.76	6,030.73
Earnings (per share)					
Quarter Ending Jun-12	7	0.16	0.22	0.13	0.11
Quarter Ending Sep-12	6	0.14	0.22	0.05	0.01
Year Ending Sep-12	9	2.31	2.38	2.22	2.45
Year Ending Sep-13	9	2.48	2.57	2.33	2.53
LT Growth Rate (%)	3	5.37	6.00	5.00	3.88

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
Thomson Reuters Stock Report - ATMOS ENERGY CORPORATION (ATO-N) Provider: Thomson Reuters Stock Report	**$25.00** BUY
ATMOS ENERGY CORP (ATO) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	**$25.00** BUY
Trading Report for (ATO). A detailed report, including free correlated market analysis, and updates. Provider: Stock Traders Daily	**$58.00** BUY
The Investment Rate - a measure of investment demand. Provider: Stock Traders Daily	**$495.00** BUY
ValuEngine Detailed Valuation Report for ATO Provider: ValuEngine, Inc.	**$127.00** BUY

» More Analyst Research

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	1,616.09	1,243.45	372.64	23.06
Quarter Ending Dec-11	1,187.74	1,124.62	63.12	5.31
Quarter Ending Sep-11	819.10	789.26	29.84	3.64
Quarter Ending Jun-11	922.74	843.61	79.13	8.58
Quarter Ending Mar-11	2,147.16	1,617.29	529.88	24.68
Earnings (per share)				
Quarter Ending Mar-12	1.43	1.28	0.15	10.38
Quarter Ending Dec-11	0.85	0.61	0.24	27.96
Quarter Ending Sep-11	0.03	0.08	0.05	140.24
Quarter Ending Jun-11	0.07	0.04	0.03	45.43
Quarter Ending Mar-11	1.39	1.35	0.04	2.97

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	847.55	847.55	845.73	819.62	866.78
Quarter Ending Sep-12	763.64	763.64	754.80	728.90	769.37
Year Ending Sep-12	4,055.41	4,055.41	4,124.38	4,318.39	5,067.51
Year Ending Sep-13	4,127.64	4,127.64	4,197.69	4,460.17	6,030.73
Earnings (per share)					
Quarter Ending Jun-12	0.16	0.16	0.16	0.13	0.11
Quarter Ending Sep-12	0.14	0.14	0.12	0.07	0.01
Quarter Ending Sep-12	2.31	2.31	2.31	2.33	2.45
Quarter Ending Sep-13	2.48	2.48	2.48	2.49	2.53

Analysts:

Consolidated Edison Inc (ED.N)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - MULTILINE

OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

ED.N on New York Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
62.98USD 3:12pm EDT	$-0.50(-0.79%)	$63.48	$63.64	246,318	$63.60
		Open $63.63	Day's Low $62.93	Avg. Vol 1,623,932	52-wk Low $49.18

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.57	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	0	0	0	0
(2) OUTPERFORM	0	0	0	0
(3) HOLD	11	11	13	13
(4) UNDERPERFORM	6	6	5	7
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	3.35	3.35	3.28	3.35

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	1.01
Q4	0.74

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	4	3,111.04	3,173.15	3,049.26	3,599.58
Quarter Ending Sep-12	4	3,816.21	3,872.80	3,765.71	4,512.48
Year Ending Dec-12	12	13,576.30	15,605.00	12,875.50	14,554.40
Year Ending Dec-13	11	14,116.80	16,446.00	13,119.10	15,211.30
Earnings (per share)					
Quarter Ending Jun-12	8	0.57	0.64	0.54	0.54
Quarter Ending Sep-12	8	1.37	1.44	1.18	1.32
Year Ending Dec-12	17	3.74	3.81	3.69	3.91
Year Ending Dec-13	15	3.84	3.90	3.74	3.82
LT Growth Rate (%)	8	3.40	4.00	2.80	3.67

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	3,464.77	3,078.00	386.77	11.16
Quarter Ending Dec-11	3,453.01	2,967.00	486.01	14.08
Quarter Ending Sep-11	3,906.12	3,629.00	277.12	7.09
Quarter Ending Jun-11	3,058.40	2,993.00	65.40	2.14
Quarter Ending Mar-11	3,820.55	3,349.00	471.55	12.34
Earnings (per share)				
Quarter Ending Mar-12	1.04	1.01	0.03	2.45
Quarter Ending Dec-11	0.72	0.74	0.02	3.35
Quarter Ending Sep-11	1.33	1.33	0.00	0.22
Quarter Ending Jun-11	0.53	0.57	0.04	7.12
Quarter Ending Mar-11	1.00	0.98	0.02	1.75

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	3,111.04	3,111.04	3,109.61	3,302.91	3,599.58
Quarter Ending Sep-12	3,816.21	3,816.21	3,816.21	4,048.05	4,512.48
Year Ending Dec-12	13,576.30	13,576.30	13,614.40	13,834.80	14,554.40
Year Ending Dec-13	14,116.80	14,116.80	14,159.00	14,433.10	15,211.30
Earnings (per share)					
Quarter Ending Jun-12	0.57	0.57	0.57	0.56	0.54
Quarter Ending Sep-12	1.37	1.37	1.35	1.36	1.32
Quarter Ending Dec-12	3.74	3.74	3.74	3.74	3.91
Quarter Ending Dec-13	3.84	3.84	3.85	3.84	3.82

Q3	**1.33**
Q2	**0.57**
Q1	**0.98**

Future Estimates

Q1 12	**0.54**
Q4 12	**1.18**

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CONSOLIDATED EDISON INC NEWS

- **New York City has enough power for summer-Con Edison**
- **Pipeline leak disrupts some natgas supply in NYC area**
- **Pipeline leak disrupts some natgas supply in NYC area**
- **Thieves stealing manhole covers in New York City, utility says**
- **Thieves stealing manhole covers in New York City, utility says**

» More ED.N News

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
CONSOLIDATED EDISON INC (ED) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	$25.00 BUY
Trading Report for (ED). A detailed report, including free correlated market analysis, and updates. Provider: Stock Traders Daily	$58.00 BUY
The Investment Rate - a measure of investment demand. Provider: Stock Traders Daily	$495.00 BUY
Thomson Reuters Stock Report - CONSOLIDATED EDISON, INC. (ED-N) Provider: Thomson Reuters Stock Report	$25.00 BUY
ValuEngine Detailed Valuation Report for ED Provider: ValuEngine, Inc.	$127.00 BUY

» More Analyst Research

Analysts:

Integrys Energy Group Inc (TEG.N)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - MULTILINE

OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

TEG.N on New York Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
57.35USD 3:12pm EDT	$0.30(+0.53%)	$57.05	$57.55	100,914	$57.05
		Open $57.13	Day's Low $56.80	Avg. Vol 413,537	52-wk Low $42.76

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.40	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	1	1	1	1
(2) OUTPERFORM	0	0	0	0
(3) HOLD	7	7	7	7
(4) UNDERPERFORM	0	0	0	0
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.75	2.75	2.75	2.75

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	1.55
Q4	1.01
Q3	0.43
Q2	0.38
Q1	1.56

Future Estimates

Q1 12	0.33
Q4 12	0.18

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INTEGRYS ENERGY GROUP INC NEWS

» More TEG.N News

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE

SALES (in millions)					
Quarter Ending Jun-12	3	1,055.67	1,097.00	1,017.00	--
Quarter Ending Sep-12	3	993.50	1,018.00	950.50	--
Year Ending Dec-12	4	4,694.73	5,018.00	4,335.90	5,563.58
Year Ending Dec-13	3	4,849.80	5,217.00	4,547.40	6,115.50
Earnings (per share)					
Quarter Ending Jun-12	6	0.40	0.50	0.33	--
Quarter Ending Sep-12	6	0.42	0.51	0.18	--
Year Ending Dec-12	8	3.43	3.50	3.40	3.62
Year Ending Dec-13	7	3.64	3.70	3.60	3.76
LT Growth Rate (%)	4	7.20	13.80	5.00	7.00

» More Analyst Research

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	1,720.33	1,251.30	469.03	27.26
Quarter Ending Dec-11	1,737.80	1,132.10	605.70	34.85
Quarter Ending Sep-11	1,071.90	938.70	133.20	12.43
Quarter Ending Jun-11	1,118.05	1,010.80	107.25	9.59
Quarter Ending Mar-11	1,871.45	1,627.10	244.35	13.06
Earnings (per share)				
Quarter Ending Mar-12	1.57	1.55	0.02	1.17
Quarter Ending Dec-11	0.98	1.01	0.03	3.06
Quarter Ending Sep-11	0.40	0.43	0.03	8.59
Quarter Ending Jun-11	0.48	0.38	0.10	20.83
Quarter Ending Mar-11	1.62	1.56	0.06	3.70

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	1,055.67	1,055.67	1,055.67	1,103.67	--
Quarter Ending Sep-12	993.50	993.50	993.50	1,035.63	--
Year Ending Dec-12	4,694.73	4,694.73	4,694.73	5,063.42	5,563.58
Year Ending Dec-13	4,849.80	4,849.80	4,849.80	5,329.00	6,115.50
Earnings (per share)					
Quarter Ending Jun-12	0.40	0.40	0.40	0.41	--
Quarter Ending Sep-12	0.42	0.42	0.42	0.40	--
Quarter Ending Dec-12	3.43	3.43	3.44	3.48	3.62
Quarter Ending Dec-13	3.64	3.64	3.64	3.59	3.76

Analysts:

Northwest Natural Gas Co (NWN.N)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - NATURAL GAS

OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

NWN.N on New York Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
47.68USD 2:49pm EDT	$0.33(+0.70%)	$47.35	$47.94	16,588	$49.49
		Open $47.35	Day's Low $47.27	Avg. Vol 106,757	52-wk Low $39.63

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Outperform	0.17	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	3	3	3	3
(2) OUTPERFORM	0	0	0	0
(3) HOLD	4	4	5	5
(4) UNDERPERFORM	0	0	0	0
(5) SELL	0	0	0	0
No Opinion	1	1	1	1
Mean Rating	2.14	2.14	2.25	2.25

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	1.51
Q4	1.09
Q3	-0.31
Q2	0.25
Q1	1.53

Future Estimates

Q1 12	0.11
Q4 12	-0.35

» More Financials

NORTHWEST NATURAL GAS CO NEWS

Corrected: Coke sets plan for plastic bottles from plants

» More NWN.N News

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	3	171.06	178.00	167.54	159.91
Quarter Ending Sep-12	3	96.19	104.00	87.51	95.70
Year Ending Dec-12	3	860.66	890.00	827.76	777.45
Year Ending Dec-13	3	885.60	914.00	835.35	842.97
Earnings (per share)					
Quarter Ending Jun-12	6	0.17	0.22	0.11	0.22
Quarter Ending Sep-12	6	-0.31	-0.27	-0.35	-0.28
Year Ending Dec-12	7	2.51	2.55	2.45	2.73
Year Ending Dec-13	7	2.70	2.80	2.55	2.66
LT Growth Rate (%)	3	4.17	4.50	4.00	3.88

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	323.31	317.49	5.82	1.80
Quarter Ending Dec-11	272.58	271.20	1.38	0.51
Quarter Ending Sep-11	81.43	93.31	11.88	14.59
Quarter Ending Jun-11	76.50	67.23	9.27	12.12
Quarter Ending Mar-11	137.31	134.51	2.80	2.04
Earnings (per share)				
Quarter Ending Mar-12	1.51	1.51	0.00	0.19
Quarter Ending Dec-11	1.05	1.09	0.04	4.24
Quarter Ending Sep-11	-0.32	-0.31	0.01	-2.61
Quarter Ending Jun-11	0.21	0.25	0.04	17.21
Quarter Ending Mar-11	1.57	1.53	0.04	2.70

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	171.06	171.06	171.06	168.32	159.91
Quarter Ending Sep-12	96.19	96.19	96.19	99.02	95.70
Year Ending Dec-12	860.66	860.66	860.66	875.12	777.45
Year Ending Dec-13	885.60	885.60	885.60	915.58	842.97
Earnings (per share)					
Quarter Ending Jun-12	0.17	0.17	0.17	0.15	0.22
Quarter Ending Sep-12	-0.31	-0.31	-0.31	-0.30	-0.28
Quarter Ending Dec-12	2.51	2.51	2.51	2.51	2.73
Quarter Ending Dec-13	2.70	2.70	2.70	2.72	2.66

Analysts:

Piedmont Natural Gas Company Inc (PNY.N)

PNY.N on New York Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
32.50USD 3:13pm EDT	$0.23(+0.71%)	$32.27	$32.64	38,046	$34.74
		Open	Day's Low	Avg. Vol	52-wk Low
		$32.29	$32.20	564,228	$25.86

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	-0.08	October	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	1	0	0	0
(2) OUTPERFORM	0	0	0	0
(3) HOLD	3	4	5	5
(4) UNDERPERFORM	4	4	4	3
(5) SELL	0	0	0	1
No Opinion	0	0	0	0
Mean Rating	3.25	3.50	3.44	3.56

EARNINGS VS. ESTIMATES

Last Five Estimates

Q2	0.7
Q1	1.05

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jul-12	3	188.79	207.14	155.00	--
Quarter Ending Oct-12	2	224.40	247.00	201.81	--
Year Ending Oct-12	3	1,245.34	1,365.00	1,182.00	1,609.96
Year Ending Oct-13	3	1,333.49	1,459.00	1,248.47	16,383.00
Earnings (per share)					
Quarter Ending Jul-12	6	-0.08	-0.07	-0.10	-0.09
Quarter Ending Oct-12	5	-0.08	-0.07	-0.10	-0.10
Year Ending Oct-12	7	1.59	1.60	1.57	1.67
Year Ending Oct-13	7	1.79	1.92	1.72	1.73
LT Growth Rate (%)	2	5.15	6.30	4.00	4.43

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Apr-12	393.54	308.43	85.11	21.63
Quarter Ending Jan-12	692.91	471.84	221.07	31.90
Quarter Ending Oct-11	200.09	192.01	8.08	4.04
Quarter Ending Jul-11	218.77	197.27	21.50	9.83
Quarter Ending Apr-11	490.67	392.57	98.10	19.99
Earnings (per share)				
Quarter Ending Apr-12	0.72	0.70	0.02	2.29
Quarter Ending Jan-12	1.19	1.05	0.14	11.76
Quarter Ending Oct-11	-0.13	-0.13	0.00	-0.00
Quarter Ending Jul-11	-0.12	-0.12	0.00	-1.40
Quarter Ending Apr-11	0.67	0.66	0.01	1.20

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jul-12	188.79	179.62	204.23	204.23	--
Quarter Ending Oct-12	224.40	224.40	201.81	201.81	--
Year Ending Oct-12	1,245.34	1,279.93	1,384.93	1,368.69	1,609.96
Year Ending Oct-13	1,333.49	1,369.81	1,462.47	1,446.85	16,383.00
Earnings (per share)					
Quarter Ending Jul-12	-0.08	-0.09	-0.11	-0.11	-0.09
Quarter Ending Oct-12	-0.08	-0.08	-0.09	-0.09	-0.10
Quarter Ending Oct-12	1.59	1.59	1.58	1.59	1.67
Quarter Ending Oct-13	1.79	1.79	1.78	1.77	1.73

Q4	**-0.13**
Q3	**-0.12**
Q2	**0.66**
Future Estimates	
Q2 12	**-0.102**
Q1 12	**-0.1**

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PIEDMONT NATURAL GAS COMPANY INC NEWS

TEXT-S&P rates Piedmont Natural Gas CP program 'A-1'

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ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
Trading Report for (PNY). A detailed report, including free correlated market analysis, and updates. Provider: Stock Traders Daily	**$58.00** BUY
PIEDMONT NATURAL GAS CO (PNY) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	**$25.00** BUY
The Investment Rate - a measure of investment demand. Provider: Stock Traders Daily	**$495.00** BUY
Thomson Reuters Stock Report - PIEDMONT NATURAL GAS COMPANY, INC. (PNY-N) Provider: Thomson Reuters Stock Report	**$25.00** BUY
ValuEngine Detailed Valuation Report for PNY Provider: ValuEngine, Inc.	**$127.00** BUY

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Analysts:

Southern Co (SO.N)

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OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

SO.N on New York Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
47.94USD 3:14pm EDT	$-0.35(-0.72%)	$48.29	$48.41	422,435	$48.45
		Open $48.40	Day's Low $47.88	Avg. Vol 3,835,063	52-wk Low $35.73

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.68	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	4	4	3	3
(2) OUTPERFORM	0	2	1	1
(3) HOLD	14	12	13	14
(4) UNDERPERFORM	3	3	3	3
(5) SELL	1	1	1	1
No Opinion	0	0	0	0
Mean Rating	2.86	2.77	2.90	2.91

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.42
Q4	0.3

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	5	4,730.44	4,929.00	4,562.86	4,043.34
Quarter Ending Sep-12	5	5,885.22	6,572.02	5,534.94	5,467.44
Year Ending Dec-12	15	18,289.00	19,150.00	17,399.00	18,217.60
Year Ending Dec-13	14	19,081.80	20,046.00	18,072.00	18,595.50
Earnings (per share)					
Quarter Ending Jun-12	11	0.68	0.76	0.63	0.67
Quarter Ending Sep-12	11	1.15	1.30	1.03	1.15
Year Ending Dec-12	22	2.65	2.70	2.55	2.70
Year Ending Dec-13	20	2.82	2.90	2.70	2.85
LT Growth Rate (%)	9	5.64	6.70	4.80	5.60

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	4,050.80	3,604.00	446.80	11.03
Quarter Ending Dec-11	4,010.24	3,696.00	314.24	7.84
Quarter Ending Sep-11	5,902.21	5,430.00	472.21	8.00
Quarter Ending Jun-11	4,482.28	4,521.00	38.72	0.86
Quarter Ending Mar-11	3,973.95	4,010.00	36.05	0.91
Earnings (per share)				
Quarter Ending Mar-12	0.46	0.42	0.04	9.27
Quarter Ending Dec-11	0.30	0.30	0.00	1.21
Quarter Ending Sep-11	1.04	1.07	0.03	2.54
Quarter Ending Jun-11	0.64	0.71	0.07	11.22
Quarter Ending Mar-11	0.51	0.50	0.01	1.17

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	4,730.44	4,730.44	4,748.28	4,823.62	4,043.34
Quarter Ending Sep-12	5,885.22	5,885.22	5,892.23	5,822.60	5,467.44
Year Ending Dec-12	18,289.00	18,289.00	18,311.60	18,504.30	18,217.60
Year Ending Dec-13	19,081.80	19,081.80	19,116.00	19,276.00	18,595.50
Earnings (per share)					
Quarter Ending Jun-12	0.68	0.68	0.69	0.73	0.67
Quarter Ending Sep-12	1.15	1.15	1.14	1.11	1.15
Quarter Ending Dec-12	2.65	2.65	2.65	2.66	2.70
Quarter Ending Dec-13	2.82	2.82	2.81	2.81	2.85

Q3	**1.07**
Q2	**0.71**
Q1	**0.5**
Future Estimates	
Q1 12	**0.628**
Q4 12	**1.029**

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SOUTHERN CO NEWS

Southern, Duke push US coal gasification; others quit

Southern boosts natgas use 40 pct, coal down 20 pct

UPDATE 2-State re-issues certificate for Southern's Kemper coal plant

Mississippi re-issues certificate for Southern's coal plant

Mississippi allows Southern Co to keep building $2.8 billion coal plant

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ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
Trading Report for (SO). A detailed report, including free correlated market analysis, and updates. Provider: Stock Traders Daily	$58.00 BUY
SOUTHERN CO (SO) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	$25.00 BUY
The Investment Rate - a measure of investment demand. Provider: Stock Traders Daily	$495.00 BUY
Wright Investors Service Comprehensive Report for Southern Company (The) Provider: Wright Reports	$483.00 BUY
Thomson Reuters Stock Report - SOUTHERN COMPANY (THE) (SO-N) Provider: Thomson Reuters Stock Report	$25.00 BUY

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Analysts:

Vectren Corp (VVC.N)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - NATURAL GAS

OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

VVC.N on New York Stock Exchange	Price Change (% chg)				
29.93USD 3:14pm EDT	$0.09(+0.30%)	Prev Close $29.84	Day's High $30.00	Volume 62,381	52-wk High $30.69
		Open $29.92	Day's Low $29.71	Avg. Vol 597,814	52-wk Low $23.65

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.22	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	0	0	0	0
(2) OUTPERFORM	0	0	0	0
(3) HOLD	6	6	6	7
(4) UNDERPERFORM	0	0	0	0
(5) SELL	0	0	0	0
No Opinion	1	1	1	1
Mean Rating	3.00	3.00	3.00	3.00

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.62
Q4	0.56

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	2	498.57	506.00	491.14	--
Quarter Ending Sep-12	1	559.00	559.00	559.00	--
Year Ending Dec-12	4	2,379.78	2,450.00	2,256.11	2,227.43
Year Ending Dec-13	3	2,495.63	2,633.00	2,315.89	2,633.00
Earnings (per share)					
Quarter Ending Jun-12	5	0.22	0.26	0.16	0.12
Quarter Ending Sep-12	4	0.42	0.49	0.30	0.30
Year Ending Dec-12	6	1.85	1.90	1.80	1.90
Year Ending Dec-13	5	1.95	2.00	1.88	1.97
LT Growth Rate (%)	2	5.50	6.00	5.00	5.57

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	668.58	604.60	63.98	9.57
Quarter Ending Dec-11	648.59	627.40	21.18	3.27
Quarter Ending Sep-11	425.82	539.40	113.58	26.67
Quarter Ending Jun-11	414.00	475.80	61.80	14.93
Quarter Ending Mar-11	775.80	682.60	93.20	12.01
Earnings (per share)				
Quarter Ending Mar-12	0.61	0.62	0.01	1.64
Quarter Ending Dec-11	0.58	0.56	0.02	3.68
Quarter Ending Sep-11	0.30	0.43	0.13	43.33
Quarter Ending Jun-11	0.12	0.18	0.06	55.17
Quarter Ending Mar-11	0.75	0.55	0.20	26.27

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	498.57	506.00	506.00	506.00	--
Quarter Ending Sep-12	559.00	559.00	559.00	559.00	--
Year Ending Dec-12	2,379.78	2,392.71	2,415.46	2,415.46	2,227.43
Year Ending Dec-13	2,495.63	2,509.42	2,548.75	2,548.75	2,633.00
Earnings (per share)					
Quarter Ending Jun-12	0.22	0.21	0.21	0.21	0.12
Quarter Ending Sep-12	0.42	0.42	0.42	0.44	0.30
Quarter Ending Dec-12	1.85	1.86	1.86	1.87	1.90
Quarter Ending Dec-13	1.95	1.96	1.96	1.98	1.97

Q3	**0.43**
Q2	**0.18**
Q1	**0.55**
Future Estimates	
Q1 12	**0.16**
Q4 12	**0.3**

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VECTREN CORP NEWS

» More VVC.N News

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
Trading Report for (VVC). A detailed report, including free correlated market analysis, and updates. Provider: Stock Traders Daily	**$58.00** BUY
The Investment Rate - a measure of investment demand. Provider: Stock Traders Daily	**$495.00** BUY
VECTREN CP (VVC) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	**$25.00** BUY
Thomson Reuters Stock Report - VECTREN CORPORATION (VVC-N) Provider: Thomson Reuters Stock Report	**$25.00** BUY
ValuEngine Detailed Valuation Report for VVC Provider: ValuEngine, Inc.	**$127.00** BUY

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Analysts:

WGL Holdings Inc (WGL.N)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - NATURAL GAS

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WGL.N on New York Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
40.92USD 3:15pm EDT	$0.28(+0.69%)	$40.64	$40.99	43,337	$44.99
		Open	**Day's Low**	**Avg. Vol**	**52-wk Low**
		$40.73	$40.59	330,061	$34.71

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.01	September	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	1	1	2	2
(2) OUTPERFORM	1	1	0	0
(3) HOLD	2	2	3	3
(4) UNDERPERFORM	4	4	4	4
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	3.12	3.12	3.00	3.00

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

EARNINGS VS. ESTIMATES

Last Five Estimates

Q2	1.58
Q1	1.13
Q4	-0.26
Q3	-0.03
Q2	1.53

Future Estimates

Q2 12	-0.03
Q1 12	-0.27

» More Financials

WGL HOLDINGS INC NEWS

BRIEF-Moody's Disclosures on Credit Ratings of WGL Holdings, Inc.

TEXT-S&P: Inergy, WGL Holdings ratings unaffected by plans

SALES (in millions)					
Quarter Ending Jun-12	5	504.10	522.86	480.91	--
Quarter Ending Sep-12	4	456.95	466.72	451.99	--
Year Ending Sep-12	6	2,569.34	2,753.00	2,518.01	2,608.11
Year Ending Sep-13	6	2,745.16	2,960.00	2,569.82	2,878.22
Earnings (per share)					
Quarter Ending Jun-12	7	0.01	0.13	-0.03	0.00
Quarter Ending Sep-12	6	-0.21	-0.10	-0.27	-0.25
Year Ending Sep-12	7	2.47	2.50	2.45	2.45
Year Ending Sep-13	8	2.59	2.86	2.35	2.63
LT Growth Rate (%)	3	4.60	5.50	4.10	3.67

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	1,050.98	839.44	211.53	20.13
Quarter Ending Dec-11	870.64	727.76	142.88	16.41
Quarter Ending Sep-11	473.27	448.12	25.14	5.31
Quarter Ending Jun-11	465.56	490.28	24.72	5.31
Quarter Ending Mar-11	1,082.96	1,017.22	65.74	6.07
Earnings (per share)				
Quarter Ending Mar-12	1.65	1.58	0.07	4.50
Quarter Ending Dec-11	1.12	1.13	0.00	0.44
Quarter Ending Sep-11	-0.34	-0.26	0.08	-23.84
Quarter Ending Jun-11	-0.11	-0.03	0.08	-72.30
Quarter Ending Mar-11	1.54	1.53	0.01	0.56

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	504.10	499.41	499.77	503.18	--
Quarter Ending Sep-12	456.95	456.95	457.39	462.89	--
Year Ending Sep-12	2,569.34	2,613.31	2,646.53	2,764.34	2,608.11
Year Ending Sep-13	2,745.16	2,790.25	2,821.16	2,918.63	2,878.22
Earnings (per share)					
Quarter Ending Jun-12	0.01	0.01	0.01	0.01	0.00
Quarter Ending Sep-12	-0.21	-0.21	-0.21	-0.24	-0.25
Quarter Ending Sep-12	2.47	2.47	2.47	2.51	2.45
Quarter Ending Sep-13	2.59	2.59	2.59	2.61	2.63

» More WGL.N News

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
WASHINGTON GAS LIGHT CO (WGL) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	$25.00 BUY
Thomson Reuters Stock Report - WGL HOLDINGS INCORPORATED (WGL-N) Provider: Thomson Reuters Stock Report	$25.00 BUY
WASHINGTON GAS LIGHT CO (WGL) 2-weeks forecast Provider: Pechala's Reports	$10.00 BUY
WGL Holdings Inc: Business description, financial summary, 3yr and interim financials, key statistics/ratios and historical ratio analysis. Provider: Reuters Investment Profile	$20.00 BUY
WASHINGTON GAS LIGHT CO (WGL) 12-months forecast Provider: Pechala's Reports	$15.00 BUY

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Analysts:

Wisconsin Energy Corp (WEC.N)

WEC.N on New York Stock Exchange

39.17USD
3:14pm EDT

Price Change (% chg)

$-0.08(-0.20%)

Prev Close	Day's High	Volume	52-wk High
$39.25	$39.43	411,920	$39.46
Open	**Day's Low**	**Avg. Vol**	**52-wk Low**
$39.43	$39.16	1,400,720	$27.00

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.44	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	1	2	2	2
(2) OUTPERFORM	4	3	3	2
(3) HOLD	12	11	11	14
(4) UNDERPERFORM	0	0	1	1
(5) SELL	1	1	0	0
No Opinion	0	0	0	0
Mean Rating	2.78	2.71	2.65	2.74

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.74
Q4	0.49

SALES (in millions)					
Quarter Ending Jun-12	4	987.66	1,021.54	967.00	--
Quarter Ending Sep-12	4	1,055.61	1,096.55	1,016.00	--
Year Ending Dec-12	12	4,620.22	5,562.38	4,090.00	4,787.77
Year Ending Dec-13	12	4,800.90	5,682.08	4,021.00	4,802.02
Earnings (per share)					
Quarter Ending Jun-12	8	0.44	0.45	0.42	--
Quarter Ending Sep-12	8	0.56	0.59	0.52	--
Year Ending Dec-12	16	2.28	2.33	2.24	2.27
Year Ending Dec-13	17	2.40	2.51	2.33	2.35
LT Growth Rate (%)	7	6.23	11.20	4.40	7.69

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	1,283.19	1,191.20	91.99	7.17
Quarter Ending Dec-11	1,099.04	1,113.30	14.26	1.30
Quarter Ending Sep-11	1,066.88	1,052.80	14.08	1.32
Quarter Ending Jun-11	990.61	991.70	1.09	0.11
Quarter Ending Mar-11	1,359.33	1,328.70	30.63	2.25
Earnings (per share)				
Quarter Ending Mar-12	0.73	0.74	0.01	1.02
Quarter Ending Dec-11	0.48	0.49	0.01	2.08
Quarter Ending Sep-11	0.53	0.55	0.02	3.42
Quarter Ending Jun-11	0.39	0.41	0.02	5.59
Quarter Ending Mar-11	0.66	0.72	0.06	9.09

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	987.66	987.66	987.66	1,009.79	--
Quarter Ending Sep-12	1,055.61	1,055.61	1,055.61	1,042.95	--
Year Ending Dec-12	4,620.22	4,620.22	4,620.64	4,586.62	4,787.77
Year Ending Dec-13	4,800.90	4,800.90	4,801.37	4,781.68	4,802.02
Earnings (per share)					
Quarter Ending Jun-12	0.44	0.44	0.44	0.45	--
Quarter Ending Sep-12	0.56	0.56	0.56	0.54	--
Quarter Ending Dec-12	2.28	2.28	2.28	2.40	2.27
Quarter Ending Dec-13	2.40	2.40	2.39	2.40	2.35

Q3	**0.55**
Q2	**0.41**
Q1	**0.72**
Future Estimates	
Q1 12	**0.42**
Q4 12	**0.52**

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WISCONSIN ENERGY CORP NEWS

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ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
Trading Report for (WEC). A detailed report, including free correlated market analysis, and updates. Provider: Stock Traders Daily	**$58.00** BUY
The Investment Rate - a measure of investment demand. Provider: Stock Traders Daily	**$495.00** BUY
WISCONSIN ENERGY CORP (WEC) - REPORT FOR ACTIVE TRADERS Provider: Pechala's Reports	**$25.00** BUY
Thomson Reuters Stock Report - WISCONSIN ENERGY CORPORATION (WEC-N) Provider: Thomson Reuters Stock Report	**$25.00** BUY
ValuEngine Detailed Valuation Report for WEC Provider: ValuEngine, Inc.	**$127.00** BUY

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Analysts:

Xcel Energy Inc (XEL.N)

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XEL.N on New York Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
28.71USD 3:17pm EDT	$-0.04(-0.14%)	$29.02	$28.91	569,700	$29.12
		Open	Day's Low	Avg. Vol	52-wk Low
		$28.86	$28.57	4,897,869	$21.20

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Outperform	0.34	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	4	4	4	4
(2) OUTPERFORM	3	3	3	3
(3) HOLD	10	10	10	10
(4) UNDERPERFORM	0	0	0	0
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.35	2.35	2.35	2.35

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.38
Q4	0.29
Q3	0.69
Q2	0.33
Q1	0.42

Future Estimates

Q1 12	0.3
Q4 12	0.67

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XCEL ENERGY INC NEWS

Xcel restarts TX Harrington 1 after pre-summer work

Areva signs $500 mln U.S. fuel supply contract

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CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	5	2,482.09	2,618.00	2,272.55	2,459.18
Quarter Ending Sep-12	5	3,063.11	3,544.09	2,806.00	3,192.56
Year Ending Dec-12	13	10,939.70	11,741.00	10,518.50	11,009.50
Year Ending Dec-13	13	11,360.00	12,176.00	10,822.80	11,520.60
Earnings (per share)					
Quarter Ending Jun-12	8	0.34	0.36	0.30	0.34
Quarter Ending Sep-12	8	0.71	0.75	0.67	0.66
Year Ending Dec-12	18	1.77	1.85	1.71	1.82
Year Ending Dec-13	17	1.89	1.95	1.85	1.92
LT Growth Rate (%)	12	5.14	7.60	1.90	5.64

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	2,594.14	2,578.08	16.07	0.62
Quarter Ending Dec-11	2,781.77	2,568.41	213.36	7.67
Quarter Ending Sep-11	2,897.30	2,831.60	65.70	2.27
Quarter Ending Jun-11	2,372.29	2,438.22	65.93	2.78
Quarter Ending Mar-11	2,885.84	2,816.54	69.30	2.40
Earnings (per share)				
Quarter Ending Mar-12	0.37	0.38	0.01	1.58
Quarter Ending Dec-11	0.30	0.29	0.01	3.17
Quarter Ending Sep-11	0.65	0.69	0.04	5.47
Quarter Ending Jun-11	0.31	0.33	0.02	4.96
Quarter Ending Mar-11	0.42	0.42	0.00	0.26

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	2,482.09	2,482.09	2,482.09	2,486.78	2,459.18
Quarter Ending Sep-12	3,063.11	3,063.11	3,063.11	3,075.92	3,192.56
Year Ending Dec-12	10,939.70	10,991.10	10,991.10	11,092.50	11,009.50
Year Ending Dec-13	11,360.00	11,390.50	11,390.50	11,497.00	11,520.60
Earnings (per share)					
Quarter Ending Jun-12	0.34	0.34	0.34	0.34	0.34
Quarter Ending Sep-12	0.71	0.71	0.71	0.71	0.66
Quarter Ending Dec-12	1.77	1.77	1.77	1.78	1.82
Quarter Ending Dec-13	1.89	1.89	1.89	1.89	1.92

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GAS: AGL RESOURCES INC - Stock Earnings Estimates

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AGL RESOURCES INC (NYSE)

ZACKS RANK: 3 - HOLD

GAS 39.26 ▲0.58 (1.50%) Vol. 353,133 15.00 CST

Current Quarter Estimate	0.30	Next Report Date	Aug 08, 2012
Next Quarter Estimate	0.21	EPS last quarter	1.16
Current Year Estimate	2.68	Last Quarter EPS Surprise	-12.12%
Next Year Estimate	2.99	EPS (Trailing 12 Mos.)	2.38
Expected Earnings Growth	4.28%	PE (forward)	14.42
Expected Sales Growth	-2.24%	ABR	2.57

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Premium Research: Stock Analysis

Zacks Rank ? upgraded 05/29/2012 Short-Term Rating 1-3 Months	PREMIUM
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Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 05/08/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
AGL RESOURCES INC	GAS	PREMIUM
CENTRICA PL-ADR	CPYYY	PREMIUM
ENERGEN CORP	EGN	PREMIUM
NJ RESOURCES	NJR	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	GAS	IND	S&P
Current Qtr (06/2012)	-9.7	N/A	N/A
Next Qtr (09/2012)	962.5	N/A	N/A
Current Year (06/2011)	-8.1	-0.4	6.8
Next Year (06/2012)	11.6	15.2	6.8
Past 5 Years	2.0	5.2	3.2
Next 5 Years	4.3	8.4	0.0
PE	16.3	13.8	13.0
PEG Ratio	3.4	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.30	0.21	2.68	2.99
# of Estimates	5	4	7	8
Most Recent Estimate	0.32	0.12	2.70	2.72
High Estimate	0.39	0.32	2.90	3.05
Low Estimate	0.19	0.12	2.55	2.72
Year ago EPS	0.33	0.02	2.92	2.68
Year over Year Growth Est.	-9.70%	962.50%	-8.12%	11.63%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	1	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.30	0.21	2.68	2.99
7 Days Ago	0.30	0.21	2.68	2.99
30 Days Ago	0.30	0.21	2.73	2.99
60 Days Ago	0.31	0.16	2.83	3.08
90 Days Ago	0.30	0.17	2.85	3.10

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	2.55	0.00
Zacks Consensus Estimate	0.30	0.21	2.68	2.99
Upside Potential	0.00%	0.00%	-4.85% ▼	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.16	0.87	0.02	0.33	
Estimate	1.32	0.92	0.00	0.28	
Difference	-0.16	-0.05	0.02	0.05	-0.04
Surprise	-12.12% ▼	-5.43% ▼	0.00% ▲	17.86% ▲	0.10% ▼

Earnings Transcript for GAS from 05/01/2012

Quarterly Estimates by Analyst

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LNT: ALLIANT ENERGY CORP - Stock Earnings Estimates

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ALLIANT ENERGY CORP (NYSE)

ZACKS RANK: 3 - HOLD

LNT 45.66 -0.15 (-0.33%) Vol. 249,398 15.00 CST

Current Quarter Estimate	0.41	Next Report Date	Aug 09, 2012
Next Quarter Estimate	1.35	EPS last quarter	0.50
Current Year Estimate	2.84	Last Quarter EPS Surprise	-21.88%
Next Year Estimate	3.11	EPS (Trailing 12 Mos.)	2.57
Expected Earnings Growth	6.18%	PE (forward)	16.11
Expected Sales Growth	.17%	ABR	1.6

Learn More About Estimate Research
See Brokerage Recommendations

Premium Research: Stock Analysis

Zacks Rank ? upgraded 06/19/2012 Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
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Equity Research Report ? Updated as of 06/11/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
ALLIANT ENERGY CORP	LNT	PREMIUM
UNITIL CORP	UTL	PREMIUM
DYNEGY INC	DYN	PREMIUM
ATLANTIC PWR CP	AT	PREMIUM

See all UTIL-ELEC PWR Peers

Earnings Growth Estimates

	LNT	IND	S&P
Current Qtr (06/2012)	-6.3	N/A	N/A
Next Qtr (09/2012)	20.8	N/A	N/A
Current Year (06/2011)	3.0	3.3	6.8
Next Year (06/2012)	9.3	7.4	6.8
Past 5 Years	6.3	4.0	3.2
Next 5 Years	6.2	5.1	0.0
PE	17.8	14.6	13.0
PEG Ratio	2.6	4.6	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.41	1.35	2.84	3.11
# of Estimates	4	4	10	9
Most Recent Estimate	0.45	1.31	2.80	3.00
High Estimate	0.45	1.49	3.00	3.18
Low Estimate	0.34	1.30	2.75	3.00
Year ago EPS	0.44	1.12	2.76	2.84
Year over Year Growth Est.	-6.25%	20.76%	3.01%	9.27%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	1
Up Last 30 Days	0	0	0	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.41	1.35	2.84	3.11
7 Days Ago	0.41	1.35	2.84	3.10
30 Days Ago	0.41	1.35	2.84	3.10
60 Days Ago	0.40	1.34	2.93	3.17
90 Days Ago	0.40	1.32	2.95	3.16

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	0.00	3.18
Zacks Consensus Estimate	0.41	1.35	2.84	3.11
Upside Potential	0.00%	0.00%	0.00%	2.25%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	0.50	0.51	1.12	0.44	
Estimate	0.64	0.56	1.33	0.47	
Difference	-0.14	-0.05	-0.21	-0.03	-0.11
Surprise	-21.87%	-8.93%	-15.79%	-6.38%	-13.24%

Earnings Transcript for LNT from 05/04/2012

Quarterly Estimates by Analyst

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--Estimates

ATMOS ENERGY CORP (NYSE) ZACKS RANK: 4 - SELL

ATO 34.62 ▲0.08 (0.23%) Vol. 228,248 15.00 CST

Current Quarter Estimate	0.16	Next Report Date	Aug 08, 2012
Next Quarter Estimate	0.17	EPS last quarter	1.28
Current Year Estimate	2.29	Last Quarter EPS Surprise	-10.49%
Next Year Estimate	2.48	EPS (Trailing 12 Mos.)	2.00
Expected Earnings Growth	4.78%	PE (forward)	15.07
Expected Sales Growth	-10.71%	ABR	2.57

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Zacks Rank Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank	PREMIUM
Target Price	PREMIUM
Equity Research Report Updated as of 06/01/2012	PREMIUM

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Top Peers	Ticker	Zacks Rank
ATMOS ENERGY CORP	ATO	PREMIUM
CENTRICA PL-ADR	CPYYY	PREMIUM
ENERGEN CORP	EGN	PREMIUM
NJ RESOURCES	NJR	PREMIUM

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Earnings Growth Estimates

	ATO	IND	S&P
Current Qtr (06/2012)	220.0	N/A	N/A
Next Qtr (09/2012)	179.2	N/A	N/A
Current Year (06/2011)	7.6	-0.4	6.8
Next Year (06/2012)	8.0	15.2	6.8
Past 5 Years	2.3	5.2	3.2
Next 5 Years	4.8	8.4	0.0
PE	17.3	13.8	13.0
PEG Ratio	3.2	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Zacks Consensus Estimate	0.16	0.17	2.29	2.48
# of Estimates	5	4	8	8
Most Recent Estimate	0.17	0.22	2.28	2.55
High Estimate	0.22	0.22	2.35	2.55
Low Estimate	0.13	0.12	2.22	2.33
Year ago EPS	0.05	0.06	2.13	2.29
Year over Year Growth Est.	220.00%	179.17%	7.57%	8.02%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	1	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	1	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Current	0.16	0.17	2.29	2.48
7 Days Ago	0.16	0.17	2.29	2.48
30 Days Ago	0.16	0.13	2.30	2.48
60 Days Ago	0.13	0.08	2.32	2.49
90 Days Ago	0.13	0.06	2.33	2.49

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Most Accurate Estimate	0.13	0.18	2.35	0.00
Zacks Consensus Estimate	0.16	0.17	2.29	2.48
Upside Potential	-18.75%	5.88%	2.62%	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.28	0.61	0.06	0.05	
Estimate	1.43	0.85	0.04	0.08	
Difference	-0.15	-0.24	0.02	-0.03	-0.10
Surprise	-10.49%	-28.24%	50.00%	-37.50%	-6.56%

Earnings Transcript for ATO from 02/08/2012

Quarterly Estimates by Analyst

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Annual Estimates by Analyst

ED: CONSOLIDATED EDISON INC - Stock Earnings Estimates

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--Estimates

CONSOLIDATED EDISON INC (NYSE)

ZACKS RANK: 3 - HOLD

ED 63.03 -0.45 (-0.71%) Vol. 1,324,083 15.00 CST

Current Quarter Estimate	0.57	Next Report Date	Aug 09, 2012
Next Quarter Estimate	1.35	EPS last quarter	0.94
Current Year Estimate	3.75	Last Quarter EPS Surprise	-9.62%
Next Year Estimate	3.86	EPS (Trailing 12 Mos.)	3.56
Expected Earnings Growth	3.6%	PE (forward)	16.94
Expected Sales Growth	-.32%	ABR	3.31

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Premium Research: Stock Analysis

Zacks Rank ? Short-Term Rating 1-3 Months	PREMIUM
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Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 05/07/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
CONSOLIDATED EDISON INC	ED	PREMIUM
UNITIL CORP	UTL	PREMIUM
DYNEGY INC	DYN	PREMIUM
ATLANTIC PWR CP	AT	PREMIUM

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Earnings Growth Estimates

	ED	IND	S&P
Current Qtr (06/2012)	1.2	N/A	N/A
Next Qtr (09/2012)	2.4	N/A	N/A
Current Year (06/2011)	3.5	3.3	6.8
Next Year (06/2012)	2.9	7.4	6.8
Past 5 Years	2.8	4.0	3.2
Next 5 Years	3.6	5.1	0.0
PE	17.8	14.6	13.0
PEG Ratio	4.7	4.6	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.57	1.35	3.75	3.86
# of Estimates	6	6	13	11
Most Recent Estimate	0.55	1.37	3.72	3.80
High Estimate	0.64	1.44	3.81	3.90
Low Estimate	0.51	1.18	3.70	3.80
Year ago EPS	0.56	1.32	3.62	3.75
Year over Year Growth Est.	1.19%	2.40%	3.51%	2.95%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.57	1.35	3.75	3.86
7 Days Ago	0.57	1.35	3.75	3.86
30 Days Ago	0.55	1.39	3.75	3.86
60 Days Ago	0.56	1.38	3.75	3.85
90 Days Ago	0.57	1.39	3.74	3.86

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.64	1.18	3.76	3.85
Zacks Consensus Estimate	0.57	1.35	3.75	3.86
Upside Potential	12.28%	-12.59%	0.27%	-0.26%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	0.94	0.74	1.32	0.57	
Estimate	1.04	0.71	1.33	0.53	
Difference	-0.10	0.03	-0.01	0.04	-0.01
Surprise	-9.62%	4.23%	-0.75%	7.55%	0.35%

Quarterly Estimates by Analyst

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TEG: INTEGRYS ENERGY GROUP INC - Stock Earnings Estimates

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INTEGRYS ENERGY GROUP INC (NYSE) ZACKS RANK: 3 - HOLD

TEG 57.37 ▲0.32 (0.56%) Vol. 468,519 15.00 CST

Current Quarter Estimate	0.38	Next Report Date	Aug 08, 2012
Next Quarter Estimate	0.47	EPS last quarter	1.55
Current Year Estimate	3.43	Last Quarter EPS Surprise	-1.27%
Next Year Estimate	3.63	EPS (Trailing 12 Mos.)	3.37
Expected Earnings Growth	4.5%	PE (forward)	16.64
Expected Sales Growth	-20.94%	ABR	2.71

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Premium Research: Stock Analysis

Zacks Rank ? Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 03/01/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
INTEGRYS ENERGY GROUP INC	TEG	PREMIUM
UNITIL CORP	UTL	PREMIUM
DYNEGY INC	DYN	PREMIUM
ATLANTIC PWR CP	AT	PREMIUM

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Earnings Growth Estimates

	TEG	IND	S&P
Current Qtr (06/2012)	0.7	N/A	N/A
Next Qtr (09/2012)	9.3	N/A	N/A
Current Year (06/2011)	1.4	3.3	6.8
Next Year (06/2012)	6.0	7.4	6.8
Past 5 Years	0.8	4.0	3.2
Next 5 Years	4.5	5.1	0.0
PE	16.9	14.6	13.0
PEG Ratio	3.7	4.6	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.38	0.47	3.43	3.63
# of Estimates	4	4	7	6
Most Recent Estimate	0.40	0.48	3.40	3.60
High Estimate	0.40	0.51	3.50	3.70
Low Estimate	0.33	0.45	3.40	3.60
Year ago EPS	0.38	0.43	3.38	3.43
Year over Year Growth Est.	0.66%	9.30%	1.44%	5.97%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	1	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.38	0.47	3.43	3.63
7 Days Ago	0.38	0.47	3.43	3.63
30 Days Ago	0.38	0.47	3.44	3.63
60 Days Ago	0.37	0.46	3.46	3.57
90 Days Ago	0.37	0.46	3.45	3.54

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	3.40	0.00
Zacks Consensus Estimate	0.38	0.47	3.43	3.63
Upside Potential	0.00%	0.00%	-0.88%	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.55	1.01	0.43	0.38	
Estimate	1.57	0.97	0.43	0.47	
Difference	-0.02	0.04	0.00	-0.09	-0.02
Surprise	-1.27%	4.12%	0.00%	-19.15%	-5.43%

Earnings Transcript for TEG from 05/03/2012

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NWN: NORTHWEST NAT GAS CO - Stock Earnings Estimates

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NORTHWEST NAT GAS CO (NYSE)

ZACKS RANK: 3 - HOLD

NWN 47.69 ▲0.34 (0.72%) Vol. 64,981 15.00 CST

Current Quarter Estimate	0.16	Next Report Date	Aug 08, 2012
Next Quarter Estimate	-0.31	EPS last quarter	1.51
Current Year Estimate	2.50	Last Quarter EPS Surprise	0%
Next Year Estimate	2.68	EPS (Trailing 12 Mos.)	2.54
Expected Earnings Growth	4.3%	PE (forward)	18.95
Expected Sales Growth	-5.84%	ABR	2.33

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Zacks Rank ? Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/07/2012	PREMIUM

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Top Peers	Ticker	Zacks Rank
NORTHWEST NAT GAS CO	NWN	PREMIUM
CENTRICA PL-ADR	CPYYY	PREMIUM
ENERGEN CORP	EGN	PREMIUM
NJ RESOURCES	NJR	PREMIUM

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Earnings Growth Estimates

	NWN	IND	S&P
Current Qtr (06/2012)	-35.2	N/A	N/A
Next Qtr (09/2012)	-1.3	N/A	N/A
Current Year (06/2011)	-2.0	-0.4	6.8
Next Year (06/2012)	7.3	15.2	6.8
Past 5 Years	1.3	5.2	3.2
Next 5 Years	4.3	8.4	0.0
PE	18.6	13.8	13.0
PEG Ratio	4.4	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.16	-0.31	2.50	2.68
# of Estimates	5	5	7	7
Most Recent Estimate	0.22	-0.35	2.45	2.55
High Estimate	0.22	-0.30	2.55	2.80
Low Estimate	0.11	-0.35	2.45	2.55
Year ago EPS	0.25	-0.31	2.55	2.50
Year over Year Growth Est.	-35.20%	-1.29%	-2.02%	7.26%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.16	-0.31	2.50	2.68
7 Days Ago	0.16	-0.31	2.50	2.68
30 Days Ago	0.16	-0.31	2.50	2.68
60 Days Ago	0.14	-0.31	2.50	2.70
90 Days Ago	0.14	-0.31	2.50	2.70

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	0.00	0.00
Zacks Consensus Estimate	0.16	-0.31	2.50	2.68
Upside Potential	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.51	1.09	-0.31	0.25	
Estimate	1.51	1.05	-0.33	0.23	
Difference	0.00	0.04	0.02	0.02	0.03
Surprise	0.00%	3.81%	6.06%	8.70%	6.19%

Earnings Transcript for NWN from 11/06/2010

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PNY: PIEDMONT NAT GAS INC - Stock Earnings Estimates

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--Estimates

PIEDMONT NAT GAS INC (NYSE) ZACKS RANK: 3 - HOLD

PNY 32.51 ▲0.24 (0.74%) Vol. 171,239 15.00 CST

Current Quarter Estimate	-0.09	Next Report Date	Sep 07, 2012
Next Quarter Estimate	-0.09	EPS last quarter	0.70
Current Year Estimate	1.59	Last Quarter EPS Surprise	-2.78%
Next Year Estimate	1.76	EPS (Trailing 12 Mos.)	1.50
Expected Earnings Growth	4.78%	PE (forward)	20.32
Expected Sales Growth	-8.62%	ABR	3.29

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Premium Research: Stock Analysis

Zacks Rank ? upgraded 06/12/2012 Short-Term Rating 1-3 Months	PREMIUM
Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/11/2012	PREMIUM

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Premium Research: Industry Analysis

Top Peers	Ticker	Zacks Rank
PIEDMONT NAT GAS INC	PNY	PREMIUM
CENTRICA PL-ADR	CPYYY	PREMIUM
ENERGEN CORP	EGN	PREMIUM
NJ RESOURCES	NJR	PREMIUM

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Earnings Growth Estimates

	PNY	IND	S&P
Current Qtr (07/2012)	25.0	N/A	N/A
Next Qtr (10/2012)	33.9	N/A	N/A
Current Year (06/2011)	1.2	-0.4	6.8
Next Year (06/2012)	11.1	15.2	6.8
Past 5 Years	3.2	5.2	3.2
Next 5 Years	4.8	8.4	0.0
PE	21.5	13.8	13.0
PEG Ratio	4.3	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (07/2012)	Next Quarter (10/2012)	Current Year (10/2012)	Next Year (10/2013)
Zacks Consensus Estimate	-0.09	-0.09	1.59	1.76
# of Estimates	6	5	6	7
Most Recent Estimate	-0.08	-0.07	1.60	1.79
High Estimate	-0.07	-0.07	1.60	1.80
Low Estimate	-0.13	-0.12	1.58	1.70
Year ago EPS	-0.12	-0.13	1.57	1.59
Year over Year Growth Est.	25.00%	33.85%	1.17%	11.08%

Agreement - Estimate Revisions

	Current Qtr (07/2012)	Next Qtr (10/2012)	Current Year (10/2012)	Next Year (10/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	0	1	2
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	2	2

Magnitude - Consensus Estimate Trend

	Current Quarter (07/2012)	Next Quarter (10/2012)	Current Year (10/2012)	Next Year (10/2013)
Current	-0.09	-0.09	1.59	1.76
7 Days Ago	-0.09	-0.09	1.59	1.76
30 Days Ago	-0.11	-0.09	1.59	1.75
60 Days Ago	-0.11	-0.09	1.59	1.75
90 Days Ago	-0.11	-0.09	1.59	1.75

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (07/2012)	Next Quarter (10/2012)	Current Year (10/2012)	Next Year (10/2013)
Most Accurate Estimate	-0.08	-0.08	1.59	1.75
Zacks Consensus Estimate	-0.09	-0.09	1.59	1.76
Upside Potential	11.11% ▲	11.11% ▲	0.00%	-0.57% ▼

Surprise - Reported Earnings History

	04/2012	01/2012	10/2011	07/2011	Average Surprise
Reported	0.70	1.05	-0.13	-0.12	
Estimate	0.72	1.19	-0.13	-0.11	
Difference	-0.02	-0.14	0.00	-0.01	-0.06
Surprise	-2.78% ▼	-11.76% ▼	0.00% ▲	-9.09% ▼	-7.88% ▼

Earnings Transcript for PNY from 01/05/2010

Quarterly Estimates by Analyst

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Annual Estimates by Analyst

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SO: SOUTHERN CO - Stock Earnings Estimates

SOUTHERN CO (NYSE) ZACKS RANK: 3 - HOLD

SO 47.85 -0.44 (-0.91%) Vol. 3,001,706 15.00 CST

Current Quarter Estimate	0.69	Next Report Date	Jul 25, 2012
Next Quarter Estimate	1.14	EPS last quarter	0.42
Current Year Estimate	2.65	Last Quarter EPS Surprise	-8.7%
Next Year Estimate	2.81	EPS (Trailing 12 Mos.)	2.50
Expected Earnings Growth	5.04%	PE (forward)	18.24
Expected Sales Growth	3.08%	ABR	3

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Zacks Recommendation ? Long-Term Rating 6+ Months	PREMIUM
Zacks Industry Rank ?	PREMIUM
Target Price ?	PREMIUM
Equity Research Report ? Updated as of 06/18/2012	PREMIUM

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Top Peers	Ticker	Zacks Rank
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UNITIL CORP	UTL	PREMIUM
DYNEGY INC	DYN	PREMIUM
ATLANTIC PWR CP	AT	PREMIUM

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Earnings Growth Estimates

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	SO	IND	S&P
Current Qtr (06/2012)	-2.7	N/A	N/A
Next Qtr (09/2012)	6.1	N/A	N/A
Current Year (06/2011)	3.0	3.3	6.8
Next Year (06/2012)	6.2	7.4	6.8
Past 5 Years	3.4	4.0	3.2
Next 5 Years	5.0	5.1	0.0
PE	19.3	14.6	13.0
PEG Ratio	3.6	4.6	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.69	1.14	2.65	2.81
# of Estimates	9	9	18	16
Most Recent Estimate	0.67	1.18	2.65	2.75
High Estimate	0.76	1.30	2.70	2.90
Low Estimate	0.63	1.03	2.55	2.70
Year ago EPS	0.71	1.07	2.57	2.65
Year over Year Growth Est.	-2.66%	6.13%	3.00%	6.17%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	1	1	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	1

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.69	1.14	2.65	2.81
7 Days Ago	0.69	1.14	2.65	2.81
30 Days Ago	0.69	1.13	2.65	2.81
60 Days Ago	0.74	1.11	2.66	2.81
90 Days Ago	0.73	1.11	2.67	2.82

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.68	1.09	2.67	2.76
Zacks Consensus Estimate	0.69	1.14	2.65	2.81
Upside Potential	-1.45% ▼	-4.39% ▼	0.76% ▲	-1.78% ▼

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	0.42	0.30	1.07	0.71	
Estimate	0.46	0.29	1.04	0.64	
Difference	-0.04	0.01	0.03	0.07	0.02
Surprise	-8.70% ▼	3.45% ▲	2.88% ▲	10.94% ▲	2.14% ▲

Earnings Transcript for SO from 04/25/2012

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VVC: VECTREN CORP - Stock Earnings Estimates

VECTREN CORP (NYSE) ZACKS RANK: 4 - SELL

VVC 29.95 ▲0.11 (0.37%) Vol. 295,695 15.00 CST

Current Quarter Estimate	0.24	Next Report Date	Aug 08, 2012
Next Quarter Estimate	0.45	EPS last quarter	0.62
Current Year Estimate	1.86	Last Quarter EPS Surprise	5.08%
Next Year Estimate	1.97	EPS (Trailing 12 Mos.)	1.79
Expected Earnings Growth	4.33%	PE (forward)	16.03
Expected Sales Growth	-1.59%	ABR	3.33

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Top Peers	Ticker	Zacks Rank
VECTREN CORP	VVC	PREMIUM
CENTRICA PL-ADR	CPYYY	PREMIUM
ENERGEN CORP	EGN	PREMIUM
NJ RESOURCES	NJR	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	VVC	IND	S&P
Current Qtr (06/2012)	33.3	N/A	N/A
Next Qtr (09/2012)	4.7	N/A	N/A
Current Year (06/2011)	7.6	-0.4	6.8
Next Year (06/2012)	5.6	15.2	6.8
Past 5 Years	-0.3	5.2	3.2
Next 5 Years	4.3	8.4	0.0
PE	16.7	13.8	13.0
PEG Ratio	3.7	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.24	0.45	1.86	1.97
# of Estimates	3	2	6	5
Most Recent Estimate	0.22	0.41	0.00	0.00
High Estimate	0.26	0.49	1.90	2.00
Low Estimate	0.22	0.41	1.80	1.95
Year ago EPS	0.18	0.43	1.73	1.86
Year over Year Growth Est.	33.33%	4.65%	7.61%	5.60%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	1	1
Down Last 30 Days	0	0	1	1

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.24	0.45	1.86	1.97
7 Days Ago	0.24	0.45	1.87	1.98
30 Days Ago	0.24	0.45	1.87	1.98
60 Days Ago	0.23	0.44	1.87	1.99
90 Days Ago	0.23	0.44	1.87	1.99

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.24	0.00	1.80	1.95
Zacks Consensus Estimate	0.24	0.45	1.86	1.97
Upside Potential	0.00%	0.00%	-3.23%	-1.02%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	0.62	0.56	0.43	0.18	
Estimate	0.59	0.56	0.32	0.13	
Difference	0.03	0.00	0.11	0.05	0.06
Surprise	5.08%	0.00%	34.38%	38.46%	25.97%

Earnings Transcript for VVC from 02/16/2012

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WGL: WGL HLDGS INC - Stock Earnings Estimates

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--Estimates

WGL HLDGS INC (NYSE)

ZACKS RANK: 3 - HOLD

WGL 40.96 ▲0.32 (0.79%) Vol. 129,801 15.00 CST

Current Quarter Estimate	0.00	Next Report Date	Aug 08, 2012
Next Quarter Estimate	-0.23	EPS last quarter	1.58
Current Year Estimate	2.48	Last Quarter EPS Surprise	-4.24%
Next Year Estimate	2.57	EPS (Trailing 12 Mos.)	2.42
Expected Earnings Growth	4.9%	PE (forward)	16.42
Expected Sales Growth	1.18%	ABR	2.71

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WGL HLDGS INC	WGL	PREMIUM
CENTRICA PL-ADR	CPYYY	PREMIUM
ENERGEN CORP	EGN	PREMIUM
NJ RESOURCES	NJR	PREMIUM

See all UTIL-GAS DISTR Peers

Earnings Growth Estimates

	WGL	IND	S&P
Current Qtr (06/2012)	88.9	N/A	N/A
Next Qtr (09/2012)	10.0	N/A	N/A
Current Year (06/2011)	11.0	-0.4	6.8
Next Year (06/2012)	3.8	15.2	6.8
Past 5 Years	2.0	5.2	3.2
Next 5 Years	4.9	8.4	0.0
PE	16.8	13.8	13.0
PEG Ratio	3.4	1.8	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Zacks Consensus Estimate	0.00	-0.23	2.48	2.57
# of Estimates	6	5	7	8
Most Recent Estimate	0.00	-0.23	2.48	2.61
High Estimate	0.03	-0.20	2.50	2.66
Low Estimate	-0.03	-0.27	2.45	2.35
Year ago EPS	-0.03	-0.26	2.23	2.48
Year over Year Growth Est.	88.89%	10.00%	11.02%	3.81%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Current	0.00	-0.23	2.48	2.57
7 Days Ago	0.00	-0.23	2.48	2.57
30 Days Ago	0.00	-0.23	2.48	2.57
60 Days Ago	0.00	-0.24	2.50	2.60
90 Days Ago	0.00	-0.24	2.50	2.60

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (09/2012)	Next Year (09/2013)
Most Accurate Estimate	-0.03	0.00	0.00	0.00
Zacks Consensus Estimate	0.00	-0.23	2.48	2.57
Upside Potential	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	1.58	1.13	-0.26	-0.03	
Estimate	1.65	1.13	-0.34	-0.10	
Difference	-0.07	0.00	0.08	0.07	0.03
Surprise	-4.24%▼	0.00%▲	23.53%▲	70.00%▲	29.76%▲

Earnings Transcript for WGL from 11/13/2009

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WEC: WISCONSIN ENERGY CORP - Stock Earnings Estimates

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--Estimates

WISCONSIN ENERGY CORP (NYSE) ZACKS RANK: 3 - HOLD

WEC 39.16 ▼-0.09 (-0.23%) Vol. 1,734,038 15.00 CST

Current Quarter Estimate	0.44	Next Report Date	Jul 26, 2012
Next Quarter Estimate	0.56	EPS last quarter	0.74
Current Year Estimate	2.28	Last Quarter EPS Surprise	1.37%
Next Year Estimate	2.46	EPS (Trailing 12 Mos.)	2.19
Expected Earnings Growth	5.28%	PE (forward)	17.23
Expected Sales Growth	.36%	ABR	2.23

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Equity Research Report ? Updated as of 05/03/2012	PREMIUM

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Top Peers	Ticker	Zacks Rank
WISCONSIN ENERGY CORP	WEC	PREMIUM
UNITIL CORP	UTL	PREMIUM
DYNEGY INC	DYN	PREMIUM
ATLANTIC PWR CP	AT	PREMIUM

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Earnings Growth Estimates

	WEC	IND	S&P
Current Qtr (06/2012)	7.3	N/A	N/A
Next Qtr (09/2012)	1.8	N/A	N/A
Current Year (06/2011)	4.5	3.3	6.8
Next Year (06/2012)	8.1	7.4	6.8
Past 5 Years	10.7	4.0	3.2
Next 5 Years	5.3	5.1	0.0
PE	17.9	14.6	13.0
PEG Ratio	3.3	4.6	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.44	0.56	2.28	2.46
# of Estimates	6	5	12	13
Most Recent Estimate	0.44	0.58	2.29	2.40
High Estimate	0.45	0.58	2.33	3.35
Low Estimate	0.43	0.52	2.25	2.33
Year ago EPS	0.41	0.55	2.18	2.28
Year over Year Growth Est.	7.32%	1.82%	4.47%	8.11%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	1	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	1	0	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.44	0.56	2.28	2.46
7 Days Ago	0.44	0.56	2.28	2.46
30 Days Ago	0.44	0.56	2.27	2.46
60 Days Ago	0.46	0.54	2.27	2.47
90 Days Ago	0.46	0.52	2.28	2.46

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.44	0.58	2.29	2.40
Zacks Consensus Estimate	0.44	0.56	2.28	2.46
Upside Potential	0.00%	3.57% ▲	0.44% ▲	-2.44% ▼

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	0.74	0.49	0.55	0.41	
Estimate	0.73	0.47	0.49	0.39	
Difference	0.01	0.02	0.06	0.02	0.03
Surprise	1.37% ▲	4.26% ▲	12.24% ▲	5.13% ▲	5.75% ▲

Earnings Transcript for WEC from 05/04/2012

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XEL: XCEL ENERGY INC - Stock Earnings Estimates

XCEL ENERGY INC (NYSE) ZACKS RANK: 3 - HOLD

XEL 28.70 -0.05 (-0.17%) Vol. 2,486,995 15.00 CST

Current Quarter Estimate	0.34	Next Report Date	Jul 26, 2012
Next Quarter Estimate	0.71	EPS last quarter	0.38
Current Year Estimate	1.78	Last Quarter EPS Surprise	2.7%
Next Year Estimate	1.88	EPS (Trailing 12 Mos.)	1.69
Expected Earnings Growth	4.86%	PE (forward)	16.35
Expected Sales Growth	.37%	ABR	2.19

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Zacks Industry Rank	PREMIUM
Target Price	PREMIUM
Equity Research Report Updated as of 05/22/2012	PREMIUM

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Top Peers	Ticker	Zacks Rank
XCEL ENERGY INC	XEL	PREMIUM
UNITIL CORP	UTL	PREMIUM
DYNEGY INC	DYN	PREMIUM
ATLANTIC PWR CP	AT	PREMIUM

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Earnings Growth Estimates

	XEL	IND	S&P
Current Qtr (06/2012)	3.0	N/A	N/A
Next Qtr (09/2012)	3.4	N/A	N/A
Current Year (06/2011)	3.2	3.3	6.8
Next Year (06/2012)	6.1	7.4	6.8
Past 5 Years	4.9	4.0	3.2
Next 5 Years	4.9	5.1	0.0
PE	17.2	14.6	13.0
PEG Ratio	3.4	4.6	0.0

Detailed Earnings Estimates

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Zacks Consensus Estimate	0.34	0.71	1.78	1.88
# of Estimates	8	8	16	15
Most Recent Estimate	0.33	0.71	1.78	1.87
High Estimate	0.36	0.75	1.85	1.95
Low Estimate	0.30	0.67	1.75	1.85
Year ago EPS	0.33	0.69	1.72	1.78
Year over Year Growth Est.	3.03%	3.44%	3.20%	6.14%

Agreement - Estimate Revisions

	Current Qtr (06/2012)	Next Qtr (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	1	0

Magnitude - Consensus Estimate Trend

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Current	0.34	0.71	1.78	1.88
7 Days Ago	0.34	0.71	1.78	1.88
30 Days Ago	0.34	0.71	1.78	1.88
60 Days Ago	0.34	0.71	1.78	1.88
90 Days Ago	0.34	0.70	1.78	1.88

Upside - Most Accurate Estimate versus Zacks Consensus

	Current Quarter (06/2012)	Next Quarter (09/2012)	Current Year (12/2012)	Next Year (12/2013)
Most Accurate Estimate	0.00	0.00	1.76	0.00
Zacks Consensus Estimate	0.34	0.71	1.78	1.88
Upside Potential	0.00%	0.00%	-1.12% ▼	0.00%

Surprise - Reported Earnings History

	03/2012	12/2011	09/2011	06/2011	Average Surprise
Reported	0.38	0.29	0.69	0.33	
Estimate	0.37	0.30	0.65	0.32	
Difference	0.01	-0.01	0.04	0.01	0.01
Surprise	2.70% ▲	-3.33% ▼	6.15% ▲	3.13% ▲	2.16% ▲

Earnings Transcript for XEL from 05/16/2012

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Blue Chip Economic Indicators®

Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead

Vol. 37, No. 3 March 10, 2012

Wolters Kluwer
Law & Business

Long-Range Consensus U.S. Economic Projections

I. The table below shows the latest U.S. Blue Chip Consensus[1] projections by years for 2014through 2018 an average for the five-year period 2014-2018, and an average for the next five-year period 2019-2023. There are also Top 10 and Bottom 10 averages for each variable. Apply these projections cautiously. For the most part economic and political forces over such long time spans cannot be evaluated with accuracy.

		YEAR				.	Five-Year Averages	
ECONOMIC VARIABLE		**2014**	**2015**	**2016**	**2017**	**2018**	**2014-18**	**2019-23**
		Percent Change, Full Year-Over-Prior Year						
1. Real GDP	**CONSENSUS**	**3.0**	**3.0**	**2.9**	**2.8**	**2.7**	**2.9**	**2.5**
(chained, 2005 dollars)	Top 10 Avg.	3.7	3.6	3.4	3.1	3.0	3.4	2.8
	Bottom 10 Avg.	2.3	2.5	2.5	2.4	2.3	2.4	2.2
2. GDP Chained Price Index	**CONSENSUS**	**2.1**	**2.2**	**2.2**	**2.2**	**2.1**	**2.1**	**2.2**
	Top 10 Avg.	2.7	2.8	2.7	2.8	2.8	2.8	2.7
	Bottom 10 Avg.	1.6	1.7	1.7	1.8	1.7	1.7	1.6
3. Nominal GDP	**CONSENSUS**	**5.1**	**5.2**	**5.1**	**5.0**	**4.9**	**5.1**	**4.7**
(current dollars)	Top 10 Avg.	6.1	6.0	6.0	5.9	5.7	5.9	5.4
	Bottom 10 Avg.	4.2	4.5	4.5	4.3	4.1	4.3	4.1
4. Consumer Price Index	**CONSENSUS**	**2.4**	**2.4**	**2.4**	**2.5**	**2.5**	**2.4**	**2.5**
(for all urban consumers)	Top 10 Avg.	3.0	3.1	3.1	3.2	3.1	3.1	3.1
	Bottom 10 Avg.	1.9	1.9	1.9	1.9	1.9	1.9	1.9
5. Industrial Production	**CONSENSUS**	**3.3**	**3.2**	**3.1**	**2.9**	**2.7**	**3.1**	**2.8**
(total)	Top 10 Avg.	4.4	4.1	4.1	3.8	3.8	4.1	3.7
	Bottom 10 Avg.	2.1	2.3	2.1	2.0	1.7	2.1	2.0
6. Disposable Personal Income	**CONSENSUS**	**2.7**	**2.8**	**2.8**	**2.7**	**2.5**	**2.7**	**2.5**
(chained, 2005 dollars)	Top 10 Avg.	3.5	3.5	3.3	3.1	3.0	3.3	2.8
	Bottom 10 Avg.	2.0	2.1	2.2	2.2	2.0	2.1	2.1
7. Personal Consumption Expenditures	**CONSENSUS**	**2.7**	**2.8**	**2.7**	**2.6**	**2.5**	**2.6**	**2.4**
(chained, 2005 dollars)	Top 10 Avg.	3.4	3.3	3.2	3.1	2.9	3.2	2.8
	Bottom 10 Avg.	2.0	2.2	2.2	2.1	2.0	2.1	2.0
8. Non-Residential Fixed Investment	**CONSENSUS**	**6.0**	**5.6**	**5.2**	**4.9**	**4.5**	**5.2**	**4.4**
(chained, 2005 dollars)	Top 10 Avg.	8.4	7.6	7.3	6.7	6.4	7.3	6.2
	Bottom 10 Avg.	3.3	3.4	3.5	3.2	2.5	3.2	2.8
9. Corporate Profits, Pretax	**CONSENSUS**	**5.7**	**5.9**	**5.1**	**4.6**	**4.8**	**5.2**	**5.4**
(current dollars)	Top 10 Avg.	8.7	9.3	7.8	7.2	6.9	8.0	7.0
	Bottom 10 Avg.	2.6	2.5	2.1	1.3	2.2	2.2	3.8
		Annual Average						
10. Treasury Bills, 3-Month	**CONSENSUS**	**1.3**	**2.4**	**3.2**	**3.6**	**3.7**	**2.8**	**3.7**
(percent per annum)	Top 10 Avg.	2.8	3.9	4.5	4.8	4.7	4.2	4.7
	Bottom 10 Avg.	0.2	1.0	1.7	2.2	2.4	1.5	2.6
11. Treasury Notes, 10-Year	**CONSENSUS**	**3.7**	**4.2**	**4.6**	**4.9**	**4.9**	**4.5**	**4.9**
(yield per annum)	Top 10 Avg.	4.8	5.2	5.5	5.7	5.7	5.4	5.7
	Bottom 10 Avg.	2.6	3.1	3.6	3.9	4.0	3.4	4.0
12. Unemployment Rate	**CONSENSUS**	**7.2**	**6.7**	**6.4**	**6.1**	**5.9**	**6.5**	**5.8**
(% of civilian labor force)	Top 10 Avg.	7.8	7.5	7.3	7.0	6.8	7.3	6.8
	Bottom 10 Avg.	6.5	6.0	5.5	5.2	5.1	5.7	5.1
		Total Units, Millions						
13. Housing Starts	**CONSENSUS**	**1.07**	**1.22**	**1.35**	**1.43**	**1.45**	**1.31**	**1.44**
(millions of units)	Top 10 Avg.	1.36	1.57	1.69	1.72	1.75	1.62	1.71
	Bottom 10 Avg.	0.82	0.92	1.04	1.11	1.12	1.00	1.14
14. Total Auto & Light Truck Sales	**CONSENSUS**	**15.0**	**15.4**	**15.7**	**15.8**	**15.8**	**15.5**	**15.8**
(millions of units)	Top 10 Avg.	16.1	16.4	16.7	16.8	16.7	16.5	17.0
	Bottom 10 Avg.	14.0	14.2	14.5	14.6	14.7	14.4	14.6
		Billions of Chained, 2005 Dollars						
15. Net Exports	**CONSENSUS**	**-412.6**	**-407.0**	**-411.0**	**-403.8**	**-395.6**	**-406.0**	**-379.4**
(billions of chained, 2005 dollars)	Top 10 Avg.	-320.3	-284.7	-260.8	-223.9	-184.9	-254.9	-109.4
	Bottom 10 Avg.	-520.0	-548.5	-574.3	-577.5	-592.3	-562.5	-622.1

Attachment 25a

REFER TO LIVE SPREADSHEET

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 25b

Analysts:

Canadian Utilities Ltd (CU.TO)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - MULTILINE

OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

CU.TO on Toronto Stock Exchange	Price Change (% chg)				
67.52CAD 4:15pm EDT	$1.14(+1.72%)	Prev Close $66.38	Day's High $67.52	Volume 106,441	52-wk High $72.00
		Open $66.41	Day's Low $66.35	Avg. Vol 140,353	52-wk Low $52.17

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Outperform	0.89	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	0	0	0	0
(2) OUTPERFORM	3	3	3	2
(3) HOLD	3	3	3	2
(4) UNDERPERFORM	0	0	0	0
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.50	2.50	2.50	2.50

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	1.37
Q4	0.8
Q3	0.84
Q2	0.71
Q1	1.3

Future Estimates

Q1 12	0.79
Q4 12	0.77

» More Financials

CANADIAN UTILITIES LTD NEWS

UPDATE 1-Atco, Canadian Utilities post higher profits

UPDATE 1-Atco, Canadian Utilities earnings rise

» More CU.TO News

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Year Ending Dec-12	2	3,352.46	3,421.42	3,283.50	3,209.10
Year Ending Dec-13	2	3,568.71	3,647.32	3,490.10	3,433.32
Earnings (per share)					
Quarter Ending Jun-12	4	0.89	1.06	0.79	0.68
Quarter Ending Sep-12	3	0.81	0.87	0.77	0.64
Year Ending Dec-12	6	4.06	4.20	3.98	3.74
Year Ending Dec-13	6	4.32	4.42	4.17	3.94
LT Growth Rate (%)	2	6.15	7.10	5.20	-2.60

HISTORICAL SURPRISES

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-11	820.46	809.00	11.46	1.40
Quarter Ending Dec-10	779.76	709.30	70.46	9.04
Quarter Ending Sep-10	765.41	550.70	214.71	28.05
Quarter Ending Jun-10	665.85	648.60	17.25	2.59
Quarter Ending Mar-10	804.07	748.60	55.47	6.90
Earnings (per share)				
Quarter Ending Mar-12	1.37	1.37	0.00	0.00
Quarter Ending Dec-11	0.98	0.80	0.18	18.53
Quarter Ending Sep-11	0.65	0.84	0.19	29.23
Quarter Ending Jun-11	0.63	0.71	0.07	11.81
Quarter Ending Mar-11	1.20	1.30	0.10	8.62

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Year Ending Dec-12	3,352.46	3,352.46	3,352.46	3,371.42	3,209.10
Year Ending Dec-13	3,568.71	3,568.71	3,568.71	3,559.14	3,433.32
Earnings (per share)					
Quarter Ending Jun-12	0.89	0.89	0.89	0.91	0.68
Quarter Ending Sep-12	0.81	0.81	0.81	0.81	0.64
Quarter Ending Dec-12	4.06	4.06	4.06	4.03	3.74
Quarter Ending Dec-13	4.32	4.32	4.32	4.26	3.94

ESTIMATES REVISIONS SUMMARY

	Last Week		Last 4 Weeks	
Number Of Revisions:	**Up**	**Down**	**Up**	**Down**
Revenue				

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
Thomson Reuters Stock Report - CANADIAN UTILITIES LIMITED (CU-T) Provider: Thomson Reuters Stock Report	$25.00 BUY
Wright Investors Service Comprehensive Report for Canadian Utilities Limited Provider: Wright Reports	$472.00 BUY
Canadian Utilities Ltd: Business description, financial summary, 3yr and interim financials, key statistics/ratios and historical ratio analysis. Provider: Reuters Investment Profile	$20.00 BUY
Canadian Utilities Limited- Strategy and SWOT Report Provider: Datamonitor	$125.00 BUY
CU: Major projects nearing regulatory approvals Provider: National Bank Financial	$35.00 BUY

» More Analyst Research

Analysts:

Emera Inc (EMA.TO)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - ELECTRIC

OVERVIEW | NEWS | KEY DEVELOPMENTS | PEOPLE | CHARTS | FINANCIALS | OPTIONS | ANALYSTS | RESEARCH | PULSE

EMA.TO on Toronto Stock Exchange	Price Change (% chg)	Prev Close	Day's High	Volume	52-wk High
33.16CAD 4:00pm EDT	$0.44(+1.34%)	$32.72	$33.66	268,630	$35.24
		Open $32.66	Day's Low $32.66	Avg. Vol 149,668	52-wk Low $19.95

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.29	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	0	0	0	0
(2) OUTPERFORM	2	2	2	2
(3) HOLD	5	4	4	3
(4) UNDERPERFORM	1	1	1	1
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.88	2.86	2.86	2.83

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.64
Q4	0.38

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	1	425.30	425.30	425.30	395.07
Quarter Ending Sep-12	1	334.00	334.00	334.00	435.17
Year Ending Dec-12	3	1,944.10	2,431.69	1,615.20	1,634.68
Year Ending Dec-13	3	2,025.36	2,619.98	1,613.30	1,888.12
Earnings (per share)					
Quarter Ending Jun-12	7	0.29	0.42	0.25	0.25
Quarter Ending Sep-12	6	0.37	0.41	0.33	0.32
Year Ending Dec-12	9	1.71	1.82	1.65	1.89
Year Ending Dec-13	9	1.82	1.87	1.75	2.04
LT Growth Rate (%)	4	6.45	8.50	4.60	9.55

HISTORICAL SURPRISES

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-11	467.68	554.60	86.92	18.58
Quarter Ending Dec-10	356.95	392.70	35.75	10.01
Quarter Ending Sep-10	324.94	373.50	48.56	14.94
Quarter Ending Jun-10	372.12	341.50	30.62	8.23
Quarter Ending Dec-09	310.03	389.10	79.07	25.50
Earnings (per share)				
Quarter Ending Mar-12	0.71	0.64	0.07	9.66
Quarter Ending Dec-11	0.35	0.38	0.03	8.57
Quarter Ending Sep-11	0.37	0.33	0.04	10.81
Quarter Ending Jun-11	0.30	0.24	0.06	20.53
Quarter Ending Mar-11	0.69	0.71	0.02	3.11

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	425.30	425.30	425.30	--	395.07
Quarter Ending Sep-12	334.00	334.00	334.00	--	435.17
Year Ending Dec-12	1,944.10	1,944.10	1,944.10	2,040.23	1,634.68
Year Ending Dec-13	2,025.36	2,025.36	2,025.36	2,165.22	1,888.12
Earnings (per share)					
Quarter Ending Jun-12	0.29	0.29	0.29	0.26	0.25
Quarter Ending Sep-12	0.37	0.36	0.36	0.36	0.32
Quarter Ending Dec-12	1.71	1.71	1.71	1.72	1.89
Quarter Ending Dec-13	1.82	1.82	1.82	1.84	2.04

Q3	**0.33**
Q2	**0.24**
Q1	**0.71**

Future Estimates

Q1 12	**0.25**
Q4 12	**0.33**

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EMERA INC NEWS

UPDATE 1-Algonquin bows out of deal to buy stake in First Wind

» More EMA.TO News

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
Thomson Reuters Stock Report - EMERA INC. (EMA-T) Provider: Thomson Reuters Stock Report	**$25.00** BUY
Emera Inc: Business description, financial summary, 3yr and interim financials, key statistics/ratios and historical ratio analysis. Provider: Reuters Investment Profile	**$20.00** BUY
Wright Investors Service Comprehensive Report for Emera Inc. Provider: Wright Reports	**$472.00** BUY
Emera Inc (EMA) Profile + Energy Industry Trends Analysis 2012 Provider: Plunkett Research, Ltd.	**$49.00** BUY
Emera Inc.: upgraded to Provider: SADIF-Investment Analytics, S.A.	**$35.00** BUY

» More Analyst Research

Analysts:

Enbridge Inc (ENB.TO)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - NATURAL GAS

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ENB.TO on Toronto Stock Exchange

40.10CAD
4:00pm EDT

Price Change (% chg)
$0.96(+2.45%)

Prev Close	Day's High	Volume	52-wk High
$39.14	$40.35	1,451,278	$41.50
Open	**Day's Low**	**Avg. Vol**	**52-wk Low**
$39.13	$39.05	1,748,702	$28.27

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Outperform	0.39	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	2	2	1	1
(2) OUTPERFORM	7	7	8	7
(3) HOLD	5	5	6	7
(4) UNDERPERFORM	1	1	1	1
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.33	2.33	2.44	2.50

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.5
Q4	0.37

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	5	5,097.14	6,335.25	4,645.17	3,965.78
Quarter Ending Sep-12	5	4,881.08	6,214.59	3,966.40	4,072.41
Year Ending Dec-12	7	20,692.00	25,925.70	14,412.90	18,472.30
Year Ending Dec-13	6	22,079.80	26,601.20	19,684.20	18,702.80
Earnings (per share)					
Quarter Ending Jun-12	10	0.39	0.42	0.36	0.36
Quarter Ending Sep-12	9	0.34	0.37	0.29	0.31
Year Ending Dec-12	15	1.65	1.75	1.60	1.50
Year Ending Dec-13	14	1.87	1.95	1.82	1.68
LT Growth Rate (%)	7	10.43	12.90	8.00	9.08

HISTORICAL SURPRISES

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	4,893.96	6,627.00	1,733.04	35.41
Quarter Ending Dec-11	4,433.74	5,436.00	1,002.26	22.61
Quarter Ending Sep-11	3,995.34	4,272.00	276.66	6.92
Quarter Ending Jun-11	4,071.05	4,981.00	909.95	22.35
Quarter Ending Mar-11	4,202.81	4,713.00	510.19	12.14
Earnings (per share)				
Quarter Ending Mar-12	0.51	0.50	0.01	2.44
Quarter Ending Dec-11	0.39	0.37	0.02	5.92
Quarter Ending Sep-11	0.28	0.32	0.04	12.99
Quarter Ending Jun-11	0.33	0.35	0.02	6.67
Quarter Ending Mar-11	0.44	0.44	0.01	2.04

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	5,097.14	5,097.14	5,095.54	4,765.32	3,965.78
Quarter Ending Sep-12	4,881.08	4,881.08	4,879.88	4,546.76	4,072.41
Year Ending Dec-12	20,692.00	20,692.00	20,689.00	19,411.60	18,472.30
Year Ending Dec-13	22,079.80	22,079.80	22,107.00	20,234.70	18,702.80
Earnings (per share)					
Quarter Ending Jun-12	0.39	0.39	0.39	0.39	0.36
Quarter Ending Sep-12	0.34	0.34	0.34	0.34	0.31
Quarter Ending Dec-12	1.65	1.65	1.67	1.64	1.50
Quarter Ending Dec-13	1.87	1.87	1.87	1.86	1.68

Q3	**0.32**
Q2	**0.35**
Q1	**0.445**

Future Estimates

Q1 12	**0.36**
Q4 12	**0.29**

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ENBRIDGE INC NEWS

UPDATE 1-Enbridge sees quicker Seaway expansion

RPT-Enbridge sees pipeline squeeze despite expansion

Enbridge sees pipeline squeeze despite expansion

Enbridge restarts Line 6A following planned work

Enbridge says expects no impact from 6A outage

» More ENB.TO News

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
ValuEngine - Toronto Quantitative Stock Report for ENB Provider: ValuEngine, Inc.	**$127.00** BUY
Thomson Reuters Stock Report - ENBRIDGE INC (ENB-T) Provider: Thomson Reuters Stock Report	**$25.00** BUY
ValuEngine Detailed Valuation Report for ENB Provider: ValuEngine, Inc.	**$127.00** BUY
Market Edge Equity Research Report Provider: Market Edge	**$46.00** BUY
ENBRIDGE INC (ENB) 2-weeks forecast Provider: Pechala's Reports	**$10.00** BUY

» More Analyst Research

Analysts:

Fortis Inc (FTS.TO)

Related Topics: STOCKS STOCK SCREENER MARKET DATA UTILITIES UTILITIES - ELECTRIC

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FTS.TO on Toronto Stock Exchange
33.08CAD
3:13pm EDT

Price Change (% chg)
$0.50(+1.53%)

Prev Close $32.58	Day's High $33.29	Volume 224,817	52-wk High $34.98
Open $32.65	Day's Low $32.57	Avg. Vol 702,708	52-wk Low $28.24

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.34	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	0	0	1	0
(2) OUTPERFORM	2	2	1	0
(3) HOLD	6	6	6	7
(4) UNDERPERFORM	2	2	2	2
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	3.00	3.00	2.90	3.22

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.64
Q4	0.46
Q3	0.25
Q2	0.33
Q1	0.65

Future Estimates

Q1 12	0.32
Q4 12	0.23

» More Financials

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	# of Estimates	Mean	High	Low	1 Year Ago

FORTIS INC NEWS

TEXT: S&P Affirms Fortis Inc., Sub 'A-' Ratings; Off Watch

Ex-Fortis head to be Dexia CEO before July - minister

UPDATE 1-Utility Fortis profit rises on lower tax

SALES (in millions)					
Quarter Ending Jun-12	2	833.75	862.80	804.70	863.76
Quarter Ending Sep-12	2	724.52	733.04	716.00	757.94
Year Ending Dec-12	5	3,870.18	3,988.26	3,779.50	4,128.63
Year Ending Dec-13	5	4,470.46	4,906.47	4,077.00	4,250.74
Earnings (per share)					
Quarter Ending Jun-12	4	0.34	0.34	0.32	0.33
Quarter Ending Sep-12	4	0.25	0.26	0.23	0.29
Year Ending Dec-12	6	1.74	1.78	1.69	1.84
Year Ending Dec-13	6	1.83	1.89	1.75	1.93
LT Growth Rate (%)	4	6.88	12.80	3.90	6.90

HISTORICAL SURPRISES

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	1,277.92	1,149.00	128.92	10.09
Quarter Ending Dec-11	1,078.91	1,037.00	41.91	3.88
Quarter Ending Sep-11	704.48	721.00	16.52	2.34
Quarter Ending Jun-11	813.27	850.00	36.73	4.52
Quarter Ending Mar-11	1,183.48	1,164.00	19.48	1.65
Earnings (per share)				
Quarter Ending Mar-12	0.67	0.64	0.03	4.83
Quarter Ending Dec-11	0.47	0.46	0.00	1.08
Quarter Ending Sep-11	0.24	0.25	0.01	2.33
Quarter Ending Jun-11	0.35	0.33	0.02	5.34
Quarter Ending Mar-11	0.61	0.65	0.04	5.71

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	833.75	833.75	833.75	835.03	863.76
Quarter Ending Sep-12	724.52	724.52	724.52	725.52	757.94
Year Ending Dec-12	3,870.18	3,870.18	3,863.08	3,909.87	4,128.63
Year Ending Dec-13	4,470.46	4,470.46	4,462.96	4,444.44	4,250.74
Earnings (per share)					
Quarter Ending Jun-12	0.34	0.34	0.34	0.33	0.33
Quarter Ending Sep-12	0.25	0.25	0.25	0.25	0.29
Quarter Ending Dec-12	1.74	1.74	1.74	1.75	1.84
Quarter Ending Dec-13	1.83	1.83	1.83	1.81	1.93

Belgium to appoint ex-Fortis CEO as new Dexia head: paper

Belgium to appoint ex-Fortis CEO as new Dexia head - paper

» More FTS.TO News

ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
Thomson Reuters Stock Report - FORTIS INC. (FTS-T) Provider: Thomson Reuters Stock Report	**$25.00** BUY
Fortis Inc: Business description, financial summary, 3yr and interim financials, key statistics/ratios and historical ratio analysis. Provider: Reuters Investment Profile	**$20.00** BUY
Wright Investors Service Comprehensive Report for Fortis Inc. Provider: Wright Reports	**$483.00** BUY
Fortis Inc. (FTS) - Financial Analysis Review Provider: GlobalData	**$288.00** BUY
FTS: Refreshing regulatory downside risk Provider: National Bank Financial	**$46.00** BUY

» More Analyst Research

Analysts:

TransCanada Corp (TRP.TO)

Related Topics: STOCKS STOCK SCREENER MARKET DATA ENERGY OIL / GAS TRANSPORTATION SERVICES

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TRP.TO on Toronto Stock Exchange
42.96CAD
4:00pm EDT

Price Change (% chg)
$0.67(+1.58%)

Prev Close	Day's High	Volume	52-wk High
$42.29	$43.30	1,215,373	$44.75
Open	**Day's Low**	**Avg. Vol**	**52-wk Low**
$42.46	$42.37	1,481,929	$37.00

SEARCH STOCKS

Enter company name or Symbol SEARCH

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Hold	0.52	December	19 Jun 2012

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	1	1	1	1
(2) OUTPERFORM	4	3	5	5
(3) HOLD	9	10	8	7
(4) UNDERPERFORM	1	1	1	1
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	2.67	2.73	2.60	2.57

EARNINGS VS. ESTIMATES

Last Five Estimates

Q1	0.52
Q4	0.52

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	# of Estimates	Mean	High	Low	1 Year Ago

SALES (in millions)					
Quarter Ending Jun-12	5	2,198.43	2,380.70	2,077.51	2,454.45
Quarter Ending Sep-12	5	2,307.81	2,487.33	2,142.00	2,616.97
Year Ending Dec-12	7	8,995.69	9,593.70	8,418.75	9,659.81
Year Ending Dec-13	6	9,577.42	9,875.46	8,837.66	10,452.40
Earnings (per share)					
Quarter Ending Jun-12	10	0.52	0.57	0.48	0.60
Quarter Ending Sep-12	9	0.60	0.73	0.50	0.63
Year Ending Dec-12	15	2.30	2.44	2.19	2.47
Year Ending Dec-13	14	2.52	2.70	2.31	2.68
LT Growth Rate (%)	3	7.77	8.60	7.30	6.50

HISTORICAL SURPRISES

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Mar-12	2,278.18	1,911.00	367.18	16.12
Quarter Ending Dec-11	2,296.69	2,360.00	63.31	2.76
Quarter Ending Sep-11	2,316.87	2,393.00	76.13	3.29
Quarter Ending Jun-11	2,170.83	2,143.00	27.83	1.28
Quarter Ending Mar-11	2,177.78	2,243.00	65.22	2.99
Earnings (per share)				
Quarter Ending Mar-12	0.54	0.52	0.02	3.17
Quarter Ending Dec-11	0.53	0.52	0.01	2.22
Quarter Ending Sep-11	0.57	0.59	0.02	3.35
Quarter Ending Jun-11	0.52	0.51	0.01	1.51
Quarter Ending Mar-11	0.58	0.61	0.03	5.87

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in Canadian Dollar (CAD)
Earnings and Dividend Figures in Canadian Dollar (CAD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Jun-12	2,198.43	2,198.43	2,201.43	2,273.71	2,454.45
Quarter Ending Sep-12	2,307.81	2,307.81	2,333.81	2,451.61	2,616.97
Year Ending Dec-12	8,995.69	8,995.69	9,015.98	9,470.70	9,659.81
Year Ending Dec-13	9,577.42	9,577.42	9,577.42	9,971.72	10,452.40
Earnings (per share)					
Quarter Ending Jun-12	0.52	0.52	0.52	0.54	0.60
Quarter Ending Sep-12	0.60	0.60	0.61	0.60	0.63
Quarter Ending Dec-12	2.30	2.30	2.30	2.37	2.47
Quarter Ending Dec-13	2.52	2.52	2.52	2.54	2.68

Q3	**0.59**
Q2	**0.51**
Q1	**0.61**
Future Estimates	
Q1 12	**0.48**
Q4 12	**0.5**

» More Financials

TRANSCANADA CORP NEWS

Republicans fear uncertain scope of Keystone study

Canada crude-Heavy discounts deepen with tight pipelines

UPDATE 2-TransCanada to build pipeline for Shell LNG plant

UPDATE 1-TransCanada to build gas pipeline in British Columbia

TransCanada secures "firm commitments" for Hardisty terminal

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ANALYST RESEARCH REPORTS

REPORT TITLE	PRICE
ValuEngine - Toronto Quantitative Stock Report for TRP Provider: ValuEngine, Inc.	**$127.00** BUY
Thomson Reuters Stock Report - TRANSCANADA CORPORATION (TRP-T) Provider: Thomson Reuters Stock Report	**$25.00** BUY
ValuEngine Detailed Valuation Report for TRP Provider: ValuEngine, Inc.	**$127.00** BUY
Market Edge Equity Research Report Provider: Market Edge	**$46.00** BUY
Wright Investors Service Comprehensive Report for TransCanada Corporation Provider: Wright Reports	**$495.00** BUY

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Attachment 26b

CONSENSUS FORECASTS®

Survey Date
April 10, 2012

Every month, Consensus Economics surveys over 250 prominent financial and economic forecasters for their estimates of a range of variables including future growth, inflation, interest rates and exchange rates. More than 20 countries are covered and the reference data, together with analysis and polls on topical issues, is rushed to subscribers by express mail and e-mail.

Contents

Survey Highlights

◈ Following a prolonged period of downgraded GDP forecasts, the negative outlook for the **Euro zone** has levelled out of late. The **French** government has upgraded its GDP forecast for this year as has the Swiss National Bank. The **UK** service sector is exhibiting signs of a rebound in Q1, but the pressure of austerity measures is still inhibiting European estimates. Indeed, ECB macroeconomic staff projections for the **Euro zone** have worsened sharply. **Spain** and **Italy** are having the greatest difficulty with reform proposals subject to fierce domestic opposition.

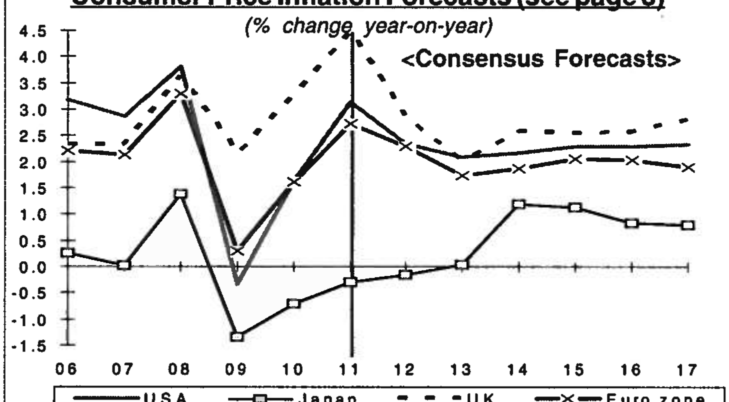
◈ Rising **oil prices** are weighing on most economies' inflation outlooks, placing further pressure on household purchasing power, particularly in **Germany**. West Texas Intermediate has eased somewhat in recent days (see page 27).

◈ This month's special survey is our regular compilation of **Long-Term Forecasts** (pages 3, 28, and 29) for the next 5-10 years. Moreover, our **Significant Changes** section (page 2) contrasts current long-term aggregate forecasts for 2018-2022 with previous aggregates going back to April 1996, allowing for an examination of trends in long-term GDP and inflation expectations.

Our next issue of **Consensus Forecasts** will be available at the end of the day on **May 17** and will include **Corporate Profits and Real Interest Rates.**

US, Japan, UK and Euro zone Long-Term Consumer Price Inflation Forecasts (see page 3)

(% change, year-on-year)



Consensus Forecasts (ISSN: 0957-0950) is published by Consensus Economics Inc.,
53 Upper Brook Street, London, W1K 2LT, United Kingdom
Tel: (44 20) 7491 3211 Fax: (44 20) 7409 2331 Web: www.consensuseconomics.com

Editor: Claire V. M. Hubbard
Assistant Editor: Thomas M. J. Crowdy
Publisher: Philip M. Hubbard

continued from page 3

France

* % change over previous year	Historical 2008	2009	2010	2011	Consensus Forecasts 2012	2013	2014	2015	2016	2017	2018-2022[1]
Gross Domestic Product*	-0.2	-2.6	1.4	1.7	0.3	1.0	1.5	1.6	1.7	1.7	1.7
Household Consumption*	0.2	0.1	1.3	0.3	0.2	0.8	1.3	1.5	1.6	1.5	1.6
Business Investment*	2.3	-11.9	2.1	4.3	0.8	2.5	2.7	2.8	2.9	2.6	2.5
Manufacturing Production*	-3.4	-13.9	4.4	3.8	-0.5	1.5	1.5	1.6	2.1	1.6	1.2
Consumer Prices*	2.8	0.1	1.5	2.1	2.1	1.8	1.8	1.9	2.0	2.1	2.1
Current Account Balance (Euro bn)	-33.7	-28.4	-33.7	-44.6	-42.8	-40.6	-31.9	-28.2	-26.2	-34.1	-29.5
10 Year Treasury Bond Yield, %[2]	3.5	3.6	3.4	3.2	3.1 [3]	3.3 [4]	3.6	3.7	3.9	4.0	4.3

United Kingdom

* % change over previous year	Historical 2008	2009	2010	2011	Consensus Forecasts 2012	2013	2014	2015	2016	2017	2018-2022[1]
Gross Domestic Product*	-1.1	-4.4	2.1	0.7	0.7	1.8	2.2	2.5	2.4	2.3	2.2
Household Consumption*	-1.4	-3.5	1.2	-1.2	0.5	1.5	2.3	2.5	2.4	2.1	2.2
Gross Fixed Investment*	-4.8	-13.4	3.1	-1.2	0.9	4.4	4.9	5.6	5.4	4.6	3.7
Manufacturing Production*	-2.6	-9.6	3.7	2.0	0.1	2.0	1.9	1.7	1.6	1.7	1.3
Retail Prices (underlying rate)*	4.3	2.0	4.8	5.3	3.2	2.6	3.5	3.4	3.7	4.3	4.1
Consumer Prices*	3.6	2.2	3.3	4.5	2.8	2.0	2.6	2.5	2.6	2.8	2.6
Current Account Balance (£ bn)	-19.8	-20.3	-48.6	-29.0	-24.5	-19.4	-9.3	-6.9	-4.2	-3.1	4.0
10 Year Treasury Bond Yield, %[2]	3.0	4.0	3.6	2.1	2.3 [3]	2.6 [4]	3.4	3.9	4.3	4.8	5.2

Italy

* % change over previous year	Historical 2008	2009	2010	2011	Consensus Forecasts 2012	2013	2014	2015	2016	2017	2018-2022[1]
Gross Domestic Product*	-1.2	-5.5	1.8	0.5	-1.5	0.2	0.6	0.9	1.2	0.8	0.9
Household Consumption*	-0.8	-1.6	1.2	0.2	-1.8	-0.4	0.6	0.8	0.9	0.7	0.7
Gross Fixed Investment*	-3.8	-11.7	1.7	-1.2	-4.5	0.2	1.2	2.3	3.2	1.2	1.2
Industrial Production*	-3.5	-18.8	6.4	0.0	-3.9	0.4	1.8	1.1	1.5	1.0	1.1
Consumer Prices*	3.3	0.8	1.5	2.8	3.0	2.4	1.5	1.4	1.7	1.9	2.1
Current Account Balance (Euro bn)	-45.2	-30.1	-54.1	-50.6	-40.5	-30.1	-31.7	-30.4	-28.8	-29.5	-28.0
10 Year Treasury Bond Yield, %[2]	4.3	4.2	4.9	7.0	5.2 [3]	5.1 [4]	4.8	4.8	3.8	4.3	4.5

Canada

* % change over previous year	Historical 2008	2009	2010	2011	Consensus Forecasts 2012	2013	2014	2015	2016	2017	2018-2022[1]
Gross Domestic Product*	0.7	-2.8	3.2	2.5	2.1	2.3	2.5	2.5	2.3	2.2	2.1
Personal Expenditure*	3.0	0.4	3.3	2.2	2.1	2.1	2.2	2.2	2.1	2.1	2.2
Machinery & Eqpt Investment*	-0.5	-19.5	11.8	13.7	4.7	7.0	6.0	4.8	4.2	3.9	3.7
Industrial Production*	-3.1	-9.5	4.9	3.5	2.9	3.2	3.5	3.2	2.8	2.7	2.4
Consumer Prices*	2.4	0.3	1.8	2.9	2.1	2.0	2.1	2.1	2.0	2.0	2.0
Current Account Balance (C$ bn)	5.3	-45.2	-50.9	-48.3	-38.3	-36.0	-28.4	-23.0	-19.1	-14.5	-11.9
10 Year Treasury Bond Yield, %[2]	2.9	3.6	3.2	1.9	2.2 [3]	2.6 [4]	3.6	4.2	4.5	4.6	4.7

Euro zone

* % change over previous year	Historical 2008	2009	2010	2011	Consensus Forecasts 2012	2013	2014	2015	2016	2017	2018-2022[1]
Gross Domestic Product*	0.3	-4.3	1.9	1.5	-0.4	0.9	1.6	1.8	1.7	1.6	1.6
Private Consumption*	0.3	-1.2	0.9	0.2	-0.4	0.6	1.2	1.1	1.1	1.1	1.1
Gross Fixed Investment*	-1.3	-12.0	-0.7	1.5	-1.3	1.5	2.3	2.8	2.7	2.6	2.5
Consumer Prices*	3.3	0.3	1.6	2.7	2.3	1.7	1.9	2.1	2.0	1.9	2.0

[1]Signifies average for period [2]End period [3]End July 2012 [4]End April 2013

Attachment 27a

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Attachment 28a

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Attachment 29a

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Attachment 29b

(Provided in electronic format only due to
document size and in order to conserve paper)

CANADIAN UTILITIES LIMITED
An ATCO Company

2012 First Quarter Report

FOR THE THREE MONTHS ENDED MARCH 31, 2012

TO THE SHARE OWNERS:

Canadian Utilities Limited reported higher earnings for the first quarter led by additional infrastructure investment in the utilities to support Alberta growth.

Earnings attributable to equity owners of Canadian Utilities were $193 million ($1.45 per share) and Adjusted Earnings were $175 million for the three months ended Mar. 31, 2012, compared to $176 million ($1.34 per share) and $166 million, respectively, in the first quarter of 2011.

ATCO Electric, ATCO Gas and ATCO Pipelines invested almost $500 million in infrastructure to support Alberta's continuing growth, adding to the rate base upon which the companies earn a return. A significant amount of this quarter's investment took place to connect major industrial customers in northeast Alberta to the province's transmission grid and to reinforce the electricity system serving that growing region of the province.

Canadian Utilities' increased earnings were partially offset by lower earnings from natural gas storage operations in ATCO Midstream.

Canadian Utilities declared a second quarter dividend for 2012 of 44.25 cents per Class A non-voting and Class B common share. Canadian Utilities' dividend per share has increased for 40 consecutive years.

FINANCIAL SUMMARY AND RECONCILIATION OF ADJUSTED EARNINGS

A financial summary and reconciliation of Adjusted Earnings to earnings attributable to equity owners is provided below:

	For the Three Months Ended March 31	
($ Millions except per share data)	**2012**	2011
Adjusted Earnings [(1)] [(2)]	**175**	166
Adjustments for Rate Regulated Activities [(3)]	**9**	4
Dividends on Equity Preferred Shares	**9**	6
Earnings Attributable to Equity Owners	**193**	176
Earnings Per Share	**1.45**	1.34
Revenues	**837**	809
Funds Generated By Operations [(1)] [(4)]	**418**	383

(1) These measures do not have standardized meaning under International Financial Reporting Standards (IFRS) and may not be comparable to similar measures used by other companies.
(2) Adjusted Earnings are earnings attributable to equity owners after adjusting for the timing of revenues and expenses associated with rate regulated activities and dividends on equity preferred shares of Canadian Utilities. Adjusted Earnings also exclude one-time gains and losses and items that are not in the normal course of business or day-to-day operations. Adjusted Earnings present earnings on the same basis as was used prior to adopting IFRS – that basis being the U.S. accounting principles for rate regulated entities – and they are a key measure used to assess segment performance, to reflect the economics of rate regulation and to facilitate comparability of Canadian Utilities' earnings with other Canadian rate regulated companies.
(3) Refer to Note 3 to the consolidated financial statements for descriptions of the adjustments for rate regulated activities and the timing of their recovery from or refund to customers.
(4) This measure is cash flow from operations before changes in non-cash working capital.

The $28 million increase in revenues was due primarily to increased rate base in the utilities, as well as the addition of ATCO Gas Australia in late July 2011. These increases were partially offset by lower flow through natural gas sales in ATCO Midstream and lower Alberta Power Pool prices.

Funds Generated by Operations increased $35 million primarily for the same reasons earnings increased, as well as higher total payments by utility customers for infrastructure.

Canadian Utilities' consolidated financial statements and management's discussion and analysis for the three months ended Mar. 31, 2012, will be available on the Canadian Utilities website (www.canadian-utilities.com), via SEDAR (www.sedar.com) or can be requested from the Company.

Alberta-based Canadian Utilities Limited, an ATCO company, with more than 6,700 employees and assets of approximately $12 billion, delivers service excellence and innovative business solutions worldwide with leading companies engaged in utilities (pipelines, natural gas and electricity transmission and distribution), energy (power generation, natural gas gathering, processing, storage and liquids extraction) and technologies (business systems solutions). More information can be found at www.canadian-utilities.com.

N.C. Southern
President & Chief Executive Officer
Deputy Chair

R.D. Southern
Chairman of the Board

CANADIAN UTILITIES LIMITED
Management's Discussion and Analysis (MD&A)
For the Three Months Ended March 31, 2012

This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements for the three months ended March 31, 2012 (2012 Interim Financial Statements), and the audited consolidated financial statements and unaudited MD&A for the year ended December 31, 2011 (2011 MD&A). **Information contained in the 2011 MD&A that is not discussed in this document remains substantially unchanged.** This MD&A is dated April 26, 2012. Additional information relating to the Corporation, including the Corporation's annual information form, is available on SEDAR at www.sedar.com.

Terms used throughout this MD&A are defined in the Glossary located at the end of the document.

Table of Contents

First Quarter Highlights

The following highlights have occurred since the 2011 MD&A dated February 21, 2012. These events are discussed in more detail throughout this MD&A:

- Adjusted Earnings for the quarter ended March 31, 2012, were $175 million compared to $166 million in the corresponding period in 2011, an increase of $9 million (5%).
- Adjusted Earnings were higher mainly due to increased rate base in the Utilities, partially offset by lower earnings from natural gas storage operations in ATCO Midstream.

Company Overview

Alberta-based Canadian Utilities Limited, an ATCO Company, with more than 6,700 employees and assets of approximately $12 billion, delivers service excellence and innovative business solutions worldwide with leading companies engaged in utilities (pipelines, natural gas and electricity transmission and distribution), energy (power generation, natural gas gathering, processing, storage and liquids extraction), and technologies (business systems solutions).

The consolidated financial statements include the accounts of Canadian Utilities Limited and all of its subsidiaries. The consolidated financial statements have been prepared in accordance with IFRS and the reporting currency is the Canadian dollar.

Segments

The Corporation operates in the following business segments:

The **Utilities** segment includes:

- the regulated distribution of natural gas by ATCO Gas;
- the regulated transmission of natural gas by ATCO Pipelines; and
- the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

The **Energy** segment includes:

- the non-regulated supply of electricity and cogeneration steam by ATCO Power;
- the regulated supply of electricity by ATCO Power; and
- the non-regulated natural gas gathering, processing, storage and natural gas liquids extraction by ATCO Midstream.

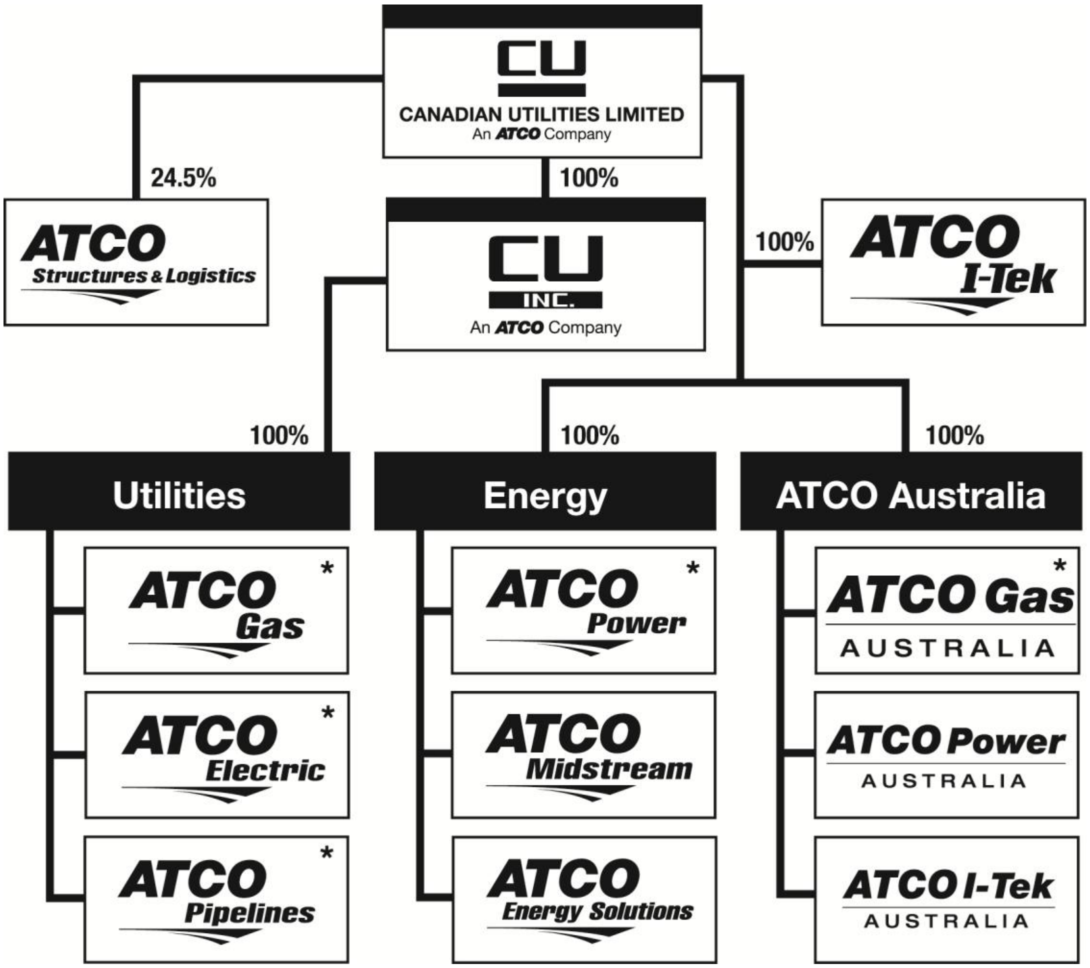
The **ATCO Australia** segment includes:

- the regulated distribution of natural gas by ATCO Gas Australia;
- the non-regulated supply of electricity and cogeneration steam by ATCO Power Australia; and
- the non-regulated provision of information technology services by ATCO I-Tek Australia.

The **Corporate & Other** segment includes:

- the Corporation's 24.5% equity investment in ATCO Structures & Logistics;
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- short term investments and commercial real estate owned in Alberta.

Simplified Organizational Structure



* *Regulated operations include ATCO Gas, ATCO Electric, ATCO Pipelines, ATCO Gas Australia and the Battle River and Sheerness generating plants of ATCO Power.*

Results of Operations

SELECTED QUARTERLY INFORMATION

The following table shows the quarterly financial information for each of the eight quarters ended June 30, 2010 through March 31, 2012.

	For the Three Months Ended (1) (2) (5)			
($ millions except per share data)	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**
2012 (3)				
Revenues	837	-	-	-
Earnings attributable to equity owners of the Corporation	193	-	-	-
Earnings per Class A and Class B Share	1.45	-	-	-
Diluted earnings per Class A and Class B Share	1.44	-	-	-
Adjusted Earnings (4)	175	-	-	-
2011 (3)				
Revenues	809	666	697	827
Earnings attributable to equity owners of the Corporation	176	98	66	156
Earnings per Class A and Class B Share	1.34	0.70	0.47	1.14
Diluted earnings per Class A and Class B Share	1.33	0.70	0.47	1.14
Adjusted Earnings (4)	166	90	106	109
2010 (3)				
Revenues	-	656	562	723
Earnings attributable to equity owners of the Corporation	-	77	87	118
Earnings per Class A and Class B Share	-	0.55	0.64	0.88
Diluted earnings per Class A and Class B Share	-	0.55	0.64	0.88
Adjusted Earnings (4)	-	69	88	123

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, revenues, earnings and Adjusted Earnings for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the U.K., the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *Quarterly information for the first quarter of 2012 and the first, second and third quarters of 2011 has been extracted from the interim consolidated financial statements, which have been prepared in accordance with IFRS. Quarterly information for the fourth quarter of 2011 was shown in Appendix 1 to the 2011 MD&A. Quarterly information for 2010 has been restated in accordance with IFRS.*

(4) *Refer to the Importance of Adjusted Earnings section for a reconciliation of Adjusted Earnings to earnings attributable to equity owners of the Corporation.*

(5) *The reporting currency is the Canadian dollar.*

The principal factors that caused variations in the results and financial condition for the previous eight quarters remain substantially unchanged from the factors discussed in the 2011 MD&A.

IMPORTANCE OF ADJUSTED EARNINGS

Adjusted Earnings are earnings attributable to equity owners of the Corporation after adjusting for the timing of revenues and expenses associated with rate regulated activities and dividends on equity preferred shares of the Corporation. Adjusted Earnings also exclude one-time gains and losses and items that are not in the normal course of business or day-to-day operations.

Adjusted Earnings are a key measure of segment earnings used by management for purposes of assessing segment performance and allocating resources. Furthermore, it is management's view that Adjusted Earnings allows a better assessment of the economics of rate regulation in Canada and Australia and facilitates comparability of the Corporation's financial results with peer companies that have either deferred the adoption of IFRS as permitted in Canada or utilize U.S. generally accepted accounting principles for rate regulated entities.

The following table reconciles Adjusted Earnings to earnings attributable to equity owners of the Corporation.

	For the Three Months Ended March 31		
($ millions)	**2012**	2011	Change (2012-2011)
Adjusted Earnings	**175**	166	9
Adjustments for Rate Regulated Activities [1]	**9**	4	5
Dividends on equity preferred shares of the Corporation	**9**	6	3
Earnings attributable to equity owners of the Corporation	**193**	176	17

(1) Adjustments for Rate Regulated Activities

Rate regulated accounting reduces the volatility of earnings, firstly, because the Corporation defers the recognition of cash received in advance of future expenditures. Under IFRS, the Corporation records revenues when amounts are billed to customers and recognizes costs when they are incurred. Secondly, under rate regulated accounting, the Corporation recognizes revenues associated with recoverable costs in advance of future billings to customers. Under IFRS, the Corporation records costs when incurred, but does not recognize their recovery until changes to customer rates are reflected in future customer billings. Thirdly, under rate regulated accounting, the Corporation recognizes revenues from regulatory decisions that pertain to current and prior periods upon receipt of the decision. Under IFRS, the Corporation recognizes revenues when customer rates are changed and amounts are billed to customers. Finally, under rate regulated accounting, amounts relating to intercompany profits that are recognized in rate base by a regulator are not eliminated upon consolidation. Under IFRS, intercompany profits included in property, plant and equipment and intangible assets are eliminated upon consolidation. The Corporation then recognizes those profits in earnings as amounts are billed to customers over the life of the related asset.

The adjustments for rate regulated activities, which are strictly timing in nature, generally fall into the four following categories. Certain adjustments may transfer from one category to another depending upon whether more or less revenue has been billed to customers than expected. The adjustments for the three months ended March 31, 2012, are shown in the following table:

($ millions)	For the Three Months Ended March 31 **2012**	2011	Change (2012-2011)
(i) Additional revenues billed in current period	**32**	34	(2)
(ii) Revenues to be billed in future period	**(33)**	(23)	(10)
(iii) Regulatory decisions related to current and prior periods	**12**	(6)	18
(iv) Elimination of intercompany profits related to the construction of property, plant and equipment and intangible assets	**(2)**	(1)	(1)
	9	4	5

(i) Additional revenues billed in current period

These adjustments are primarily comprised of future removal and site restoration costs, where customers are billed over the life of the associated assets in advance of future expenditures, and ATCO Electric's transmission capital deferrals, where the Corporation recovers from the AESO the variance between returns on forecasted versus actual rate base for projects directly assigned by the AESO.

(ii) Revenues to be billed in future period

Deferred income taxes and the impact of warmer weather are the most significant items in this category. Deferred income taxes are not recovered from customers until income taxes are paid, with the exception of federal deferred income taxes for ATCO Electric's transmission operations beginning in 2011. ATCO Gas' customer rates are based on normal temperatures. Warmer weather results in less revenue being collected than forecast, which, with the approval of the AUC, is collected from customers.

(iii) Regulatory decisions

The increase in this category was mainly the result of the following three decisions:

In December 2011, ATCO Electric received a decision approving the recovery of $10 million over the period January 2012 to March 2012 associated with higher than forecast transmission access payments. Under IFRS, these revenues are recognized in 2012 as customers are billed.

In December 2011, ATCO Gas recorded a reduction in Adjusted Earnings of $10 million associated with a general rate application decision. Under IFRS, revenues will be adjusted once the AUC approves the revised customer rates and the amount payable to customers is refunded through future billings.

Under IFRS, ATCO Gas recognized revenues of $14 million from decisions related to the Carbon Facility in the first quarter of 2011. Under rate regulated accounting, ATCO Gas had recognized these revenues prior to 2011 upon receipt of the decisions.

CONSOLIDATED REVENUES AND ADJUSTED EARNINGS

Revenues for the three months ended March 31, 2012, **increased** by $28 million (3%) over 2011. This increase was mainly due to increased rate base in the Utilities and the addition of ATCO Gas Australia on July 29, 2011. Partially offsetting these increases were lower flow through natural gas sales and lower revenues from natural gas storage operations in ATCO Midstream.

Adjusted Earnings for the three months ended March 31, 2012, **increased** by $9 million (5%) over 2011. This increase was primarily attributable to increased rate base in the Utilities and the addition of ATCO Gas Australia, offset by lower earnings from natural gas storage operations in ATCO Midstream.

CONSOLIDATED EXPENSES

	For the Three Months Ended March 31		
($ millions)	**2012**	2011	Change (2012-2011)
Costs and expenses:			
Salaries, wages and benefits	**112**	103	9
Energy transmission and transportation	**31**	11	20
Plant and equipment maintenance	**47**	37	10
Fuel costs	**80**	123	(43)
Purchased power	**16**	16	-
Materials and consumables	**9**	15	(6)
Franchise fees	**52**	62	(10)
Other expenses	**75**	72	3
	422	439	(17)
Depreciation and amortization	**102**	85	17
Interest expense	**66**	53	13
Income taxes	**60**	61	(1)

Costs and expenses for the three months ended March 31, 2012, **decreased** by $17 million (4%) compared to the corresponding period in 2011. Fuel costs decreased by $43 million primarily due to lower flow through natural gas purchases for NGL extraction in ATCO Midstream and lower fuel costs incurred at ATCO Power as a result of lower natural gas prices. These decreases were partially offset by increased Energy transmission and transportation costs of $20 million. Since the transition of ATCO Pipelines' customers to NOVA Gas Transmission Ltd. (NGTL) on October 1, 2011, ATCO Gas pays NGTL for transmission costs and ATCO Pipelines receives revenues from NGTL for transmission services. Prior to October 2011, ATCO Gas paid ATCO Pipelines for transmission services, and the associated expenses and revenues were eliminated on consolidation. Plant and equipment maintenance costs were higher due to line brushing costs in ATCO Electric and the timing of a planned outage at the Battle River generating plant in ATCO Power. Salaries, wages and benefits increased by $9 million mainly due to the acquired operations of ATCO Gas Australia.

For the three months ended March 31, 2012, **depreciation and amortization expense increased** by $17 million (20%) over 2011 primarily due to the acquisition of ATCO Gas Australia's operations and capital additions in the Utilities.

Interest expense for the three months ended March 31, 2012, **increased** by $13 million (25%) over 2011, mainly due to the issuance of $700 million of debentures on October 24, 2011, and interest on long term debt associated with the acquisition of ATCO Gas Australia. These increases were partially offset by the capitalization of interest by ATCO Electric due to increases in its capital program.

SEGMENTED INFORMATION

($ millions)	Utilities	Energy	ATCO Australia	Corporate & Other	Intersegment Eliminations	Total
	For the Three Months Ended March 31					
2012						
Revenues	**517**	**236**	**65**	**56**	**(37)**	**837**
Adjusted Earnings	**108**	**47**	**6**	**13**	**1**	**175**
Adjustments for rate regulated activities [1]	**11**	**-**	**(3)**	**-**	**1**	**9**
Dividends on equity preferred shares of the Corporation	**1**	**-**	**-**	**8**	**-**	**9**
Earnings attributable to equity owners of the Corporation	**120**	**47**	**3**	**21**	**2**	**193**
2011						
Revenues	474	300	24	50	(39)	809
Adjusted Earnings	101	54	4	7	-	166
Adjustments for rate regulated activities [1]	3	-	-	-	1	4
Dividends on equity preferred shares of the Corporation	1	-	-	5	-	6
Earnings attributable to equity owners of the Corporation	105	54	4	12	1	176

[1] *Refer to Importance of Adjusted Earnings section for a description of the adjustments.*

Utilities

Utilities **revenues** for the three months ended March 31, 2012, were $517 million, an **increase** of $43 million (9%) over 2011. This increase was primarily attributable to increased rate base, recoveries from customers of federal deferred income taxes relating to ATCO Electric's transmission operations and increased transmission revenues in ATCO Pipelines. Since the transition of ATCO Pipelines' customers to NGTL on October 1, 2011, ATCO Pipelines receives revenues from NGTL for transmission services and ATCO Gas pays NGTL for transmission costs. Prior to October 2011, ATCO Gas paid ATCO Pipelines for transmission services, and the associated expenses and revenues were eliminated on consolidation. These increases were partially offset in ATCO Gas by the effect of warmer weather and amounts collected from customers in 2011 pertaining to the Carbon Facility decisions.

Adjusted Earnings for each of the Utilities are shown in the following table:

($ millions)	**2012**	2011	Change (2012-2011)
	For the Three Months Ended March 31		
ATCO Electric	**47**	41	6
ATCO Gas	**53**	46	7
ATCO Pipelines	**8**	14	(6)
	108	101	7

Adjusted Earnings for the three months ended March 31, 2012, were $108 million, an **increase** of $7 million (7%) over 2011, mainly due to increased rate base in the Utilities, primarily in ATCO Electric, and increased customer usage in ATCO Gas. These increases were partially offset by the impact of the 2011 Generic Cost of Capital decision received in December 2011, which reduced the return on equity for all three Utilities from 9.0% to 8.75% for 2011 and 2012 (the 2011 portion was recorded upon receipt of the decision in December 2011) and reduced ATCO Pipelines' common equity ratio from 45% to 38% effective 2012.

Regulatory Developments

Pension Hearing

On September 27, 2011, the AUC issued its decision on the Utilities' pension methodology, specifically on the determination of the cost of living allowance (COLA) used in the determination of pension costs included in 2012 and future years' revenue requirements. Effective 2012 and beyond, the AUC decided that the appropriate level for annual COLA adjustments is 50% of CPI subject to a maximum COLA adjustment of 3%. This decision affects current service funding requirements in 2012 and current service and deficit funding requirements starting in 2013.

Pension cost recoveries from customers will be reduced in 2012 by $4 million, and the Utilities' Adjusted Earnings are expected to decrease by $3 million. The effect on 2013 is dependent on the results of the next actuarial valuation for funding purposes, which is required to be completed as of December 31, 2012. Based on the last actuarial valuation which was completed as of December 31, 2009, the pension cost recoveries from customers would be reduced by a further $14 million to $18 million, resulting in a decrease to the Utilities' Adjusted Earnings in 2013 of $13 million.

On March 22, 2012, the AUC denied the Utilities' review and variance application on this decision. The Utilities have applied to the Alberta Court of Appeal for leave to appeal the decision. A court date has not yet been set.

ATCO Electric

Eastern Alberta Transmission Line (EATL) Project

On March 29, 2011, ATCO Electric filed its facility application with the AUC, to build and operate a new 500kV high voltage direct current transmission line along a corridor on the east side of the province between Edmonton and Calgary. The estimated project cost, excluding capitalized interest during construction, is $1.6 billion, of which $137 million has been incurred as of March 31, 2012, for pre-construction activities, including engineering and ordering of long lead-time materials. On February 23, 2012, the Alberta government accepted the Critical Transmission Review Committee's recommendations to proceed with the project as planned and requested the AUC to re-start the regulatory process to review the facility application. The AUC has scheduled a public hearing to commence on July 23, 2012. Pre-construction activities will continue until AUC approval of the facility application is received and construction begins. The achievement of the AESO directed in-service date of mid to late 2014 remains possible, but is dependent upon receipt of final regulatory approval from the AUC, which is expected in the fourth quarter of 2012.

Hanna Region Transmission Development ("HRTD") Project

ATCO Electric's share of the major transmission reinforcement of the southeast region of the province, the HRTD project, is comprised of approximately 355 kilometres of transmission line, the construction of six new substations and modifications and expansions to a further 14 existing substations. The estimated total project cost, excluding capitalized interest during construction is approximately $735 million, of which $204 million has been incurred as of March 31, 2012 for pre-construction activities, including engineering and ordering of long-lead time materials, as permitted under existing legislation. ATCO Electric is awaiting approval from the AUC, which is anticipated in the second quarter of 2012, to proceed with construction of the project. Of the remaining project costs of $531 million, approximately $300 million is anticipated to be incurred by the end of 2012, with the balance to be incurred in the first half of 2013. The transmission infrastructure is expected to be in-service by the end of the second quarter of 2013.

Energy

Energy **revenues** for the three months ended March 31, 2012 were $236 million, a **decrease** of $64 million (21%) compared to 2011. This decrease was primarily attributed to reduced flow through natural gas sales as a result of lower volumes in ATCO Midstream's NGL extraction facilities, and lower revenues in natural gas storage operations. Further decreases in revenue were attributable to lower power prices in the U.K. merchant power market and lower Alberta Power Pool prices.

Adjusted Earnings for ATCO Power and ATCO Midstream are shown in the following table:

	For the Three Months Ended March 31		
($ millions)	**2012**	2011	Change (2012-2011)
ATCO Power			
Independent Power Plants	**25**	23	2
Regulated Power Plants	**18**	19	(1)
	43	42	1
ATCO Midstream			
Storage Operations	**(1)**	6	(7)
NGL Extraction Operations	**6**	7	(1)
Other Midstream (1)	**(2)**	(2)	-
	3	11	(8)
Other	**1**	1	-
	47	54	(7)

(1) *Other Midstream includes Gas Gathering & Processing and ATCO Midstream's Corporate Office.*

Adjusted Earnings for the three months ended March 31, 2012, **decreased** by $7 million (13%) compared to 2011, mainly due to lower earnings from natural gas storage operations in ATCO Midstream. Lower Spark Spreads in ATCO Power's independent power plants in Alberta were more than offset by $3 million of realized gains on short-dated forward power sales contracts.

Power Generation

Availability of the generating plants by geographic region is set forth below:

	For the Three Months Ended March 31		
	2012	2011	Change (2012-2011)
Independent Power Plants (1)			
Canada	**96.9%**	91.5%	5.4%
U.K.	**94.0%**	96.8%	(2.8%)
Regulated Plants (1)			
Canada	**97.6%**	97.4%	0.2%

(1) Generating plant availability will fluctuate due to the timing and duration of outages.

Merchant Operations

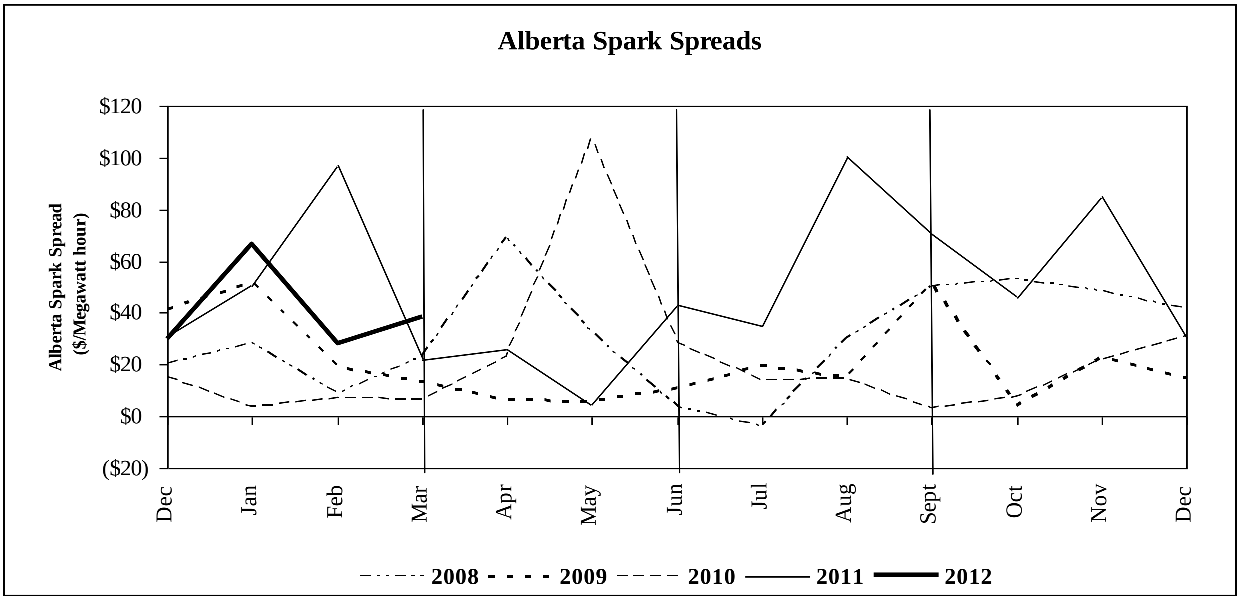
At March 31, 2012, changes in Spark Spread affect the results of approximately 665 MW of plant capacity out of a total capacity owned by ATCO Power of 2,550 MW. This capacity is comprised of approximately 410 MW in Alberta out of a total Alberta-owned capacity of 1,815 MW and all of the U.K.-owned capacity of 255 MW.

Alberta Merchant Operations

The majority of ATCO Power's electricity sales to the Alberta Power Pool are from natural gas-fired generating plants and, as a result, earnings are affected by natural gas prices and Alberta Power Pool prices. The average Alberta Power Pool electricity prices, natural gas prices and resulting Spark Spreads for the three months ended March 31, 2012, are shown in the following table:

	For the Three Months Ended March 31		
	2012	2011	Change (2012-2011)
Average Alberta Power Pool electricity price ($/MWh)	**60.12**	82.05	(27%)
Average natural gas price ($/GJ)	**2.06**	3.57	(42%)
Average Spark Spread ($/MWh)	**44.70**	55.20	(19%)

The following chart demonstrates the volatility of monthly average Spark Spreads for the Alberta electricity market since the beginning of 2008. Earnings do not necessarily correlate with these monthly average Spark Spreads as they are also dependent on short term price volatility. In addition, ATCO Power may periodically enter into forward power sales and natural gas purchase arrangements to secure favourable Alberta Spark Spreads. At March 31, 2012, there were no forward power sales or natural gas purchase contracts outstanding.

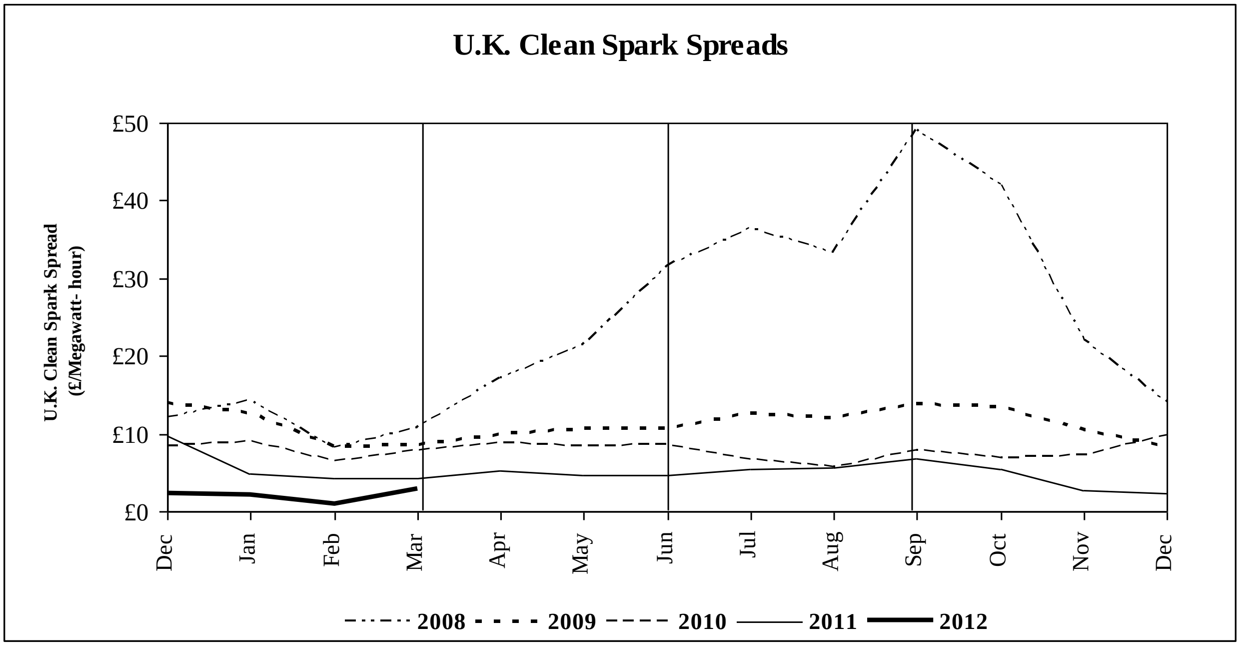


U.K. Merchant Operations

The average U.K. power prices, natural gas prices, emissions allowances and resulting Spark Spreads for the three months ended March 31, 2012, are shown in the following table:

	For the Three Months Ended March 31		
	2012	2011	Change (2012-2011)
Average U.K. power price (£/MWh)	**45.14**	48.59	(7%)
Average natural gas price (£/GJ)	**5.60**	5.40	4%
Average emissions allowance price (£/tonne of CO_2)	**6.60**	13.09	(50%)
Average Spark Spread (£/MWh)	**2.00**	4.50	(56%)

Barking's actual merchant sales are not necessarily sold using the same Spark Spread indicator used in the table above and the graph below. The table and graph depict the spot market, whereas the Barking generating plant generally utilizes a combination of available arrangements to sell its capacity: including short term bilateral transactions, as well as intra day electrical energy services transactions. The following chart demonstrates the volatility of U.K. Spark Spreads since the beginning of 2008:



Regulated Generating Plants

During the three months ended March 31, 2012, the **unearned availability incentive** account **increased** by $10 million to $78 million. The increase in the balance was primarily due to availability incentives received for both the Battle River and Sheerness generating plants during the quarter as a result of high availability. Partially offsetting this increase was the normal amortization of unearned availability incentives. During the three months ended March 31, 2012, the amortization of unearned availability incentives, recorded in revenue, remained unchanged at $5 million compared to the same period in 2011.

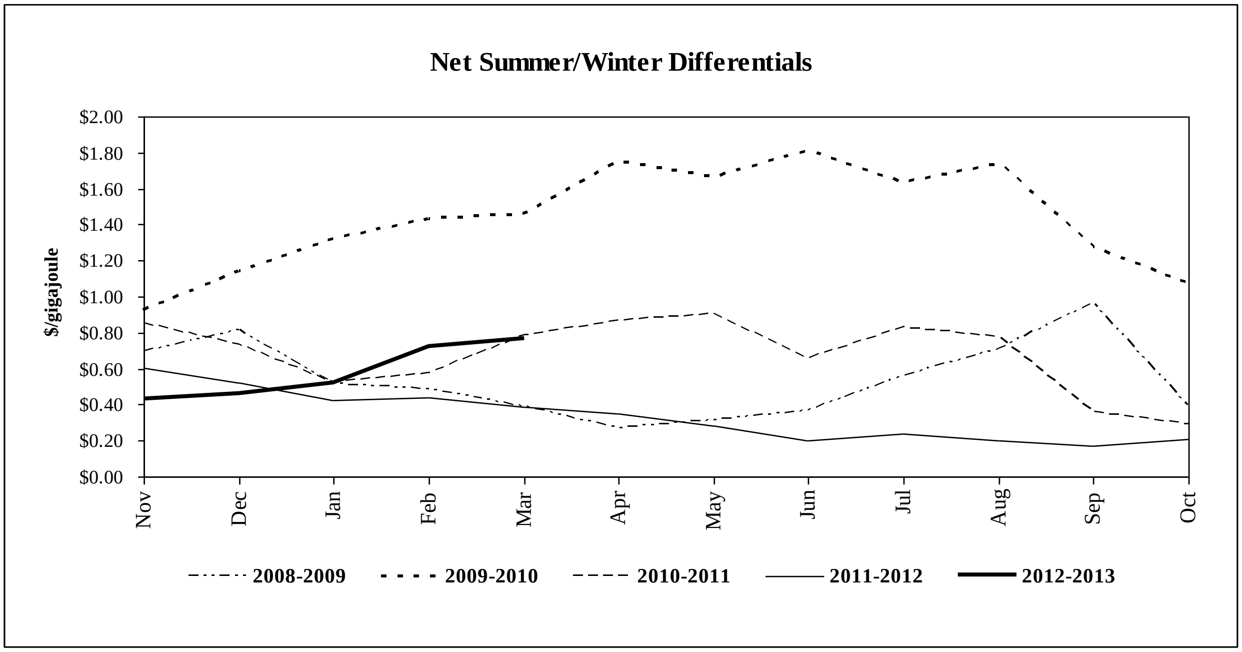
ATCO Midstream

Storage Operations

The majority of ATCO Midstream's natural gas storage revenues come from seasonal differences (summer/winter) in the price of natural gas (Storage Price Differentials). Seasonal Storage Price Differentials are differences between summer and winter natural gas prices. The storage year starts April 1 and is defined as April to October injection season and ends with the November to March withdrawal season.

Seasonal Storage Price Differentials in the 2011-2012 storage year, which ended on March 31, 2012, were lower than the Storage Price Differentials for the 2010-2011 storage year which ended on March 31, 2011, resulting in lower storage revenues in the first quarter of 2012. Storage Price Differentials for the upcoming 2012-2013 storage year are currently higher compared to the prior year. Revenues for storage contracts in this storage year will be recognized commencing April 1, 2012.

Storage Price Differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal differentials experienced during the storage periods from the 2008-2009 storage year to the 2012-2013 storage year. Storage Price Differentials at any point in time may not be indicative of the storage revenue and earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.



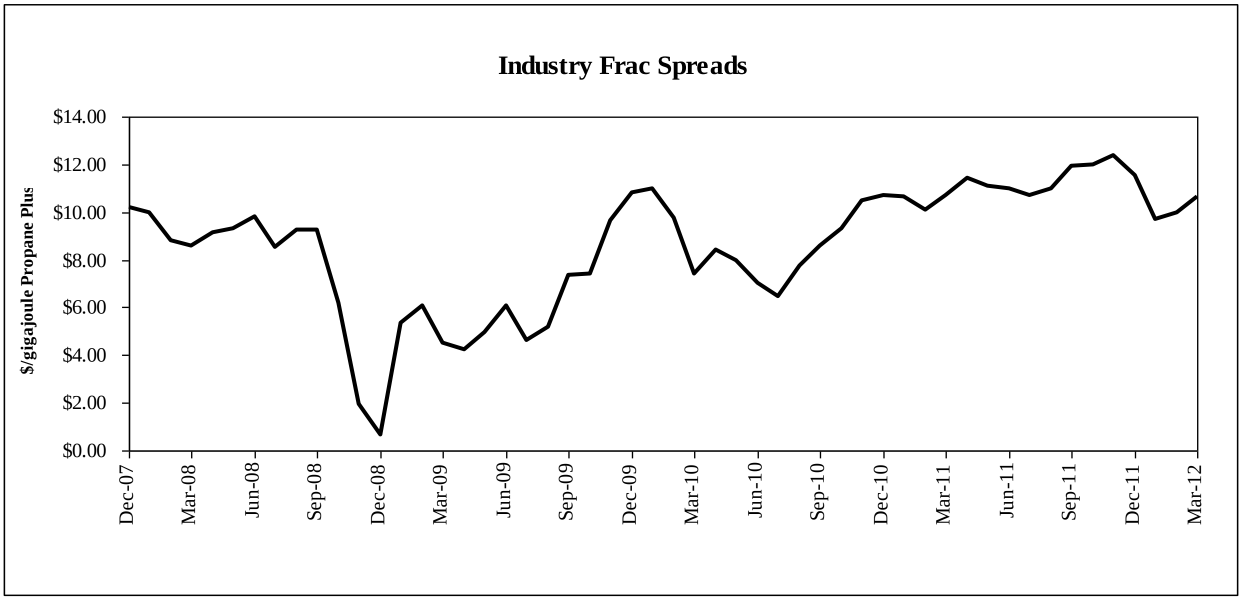
(1) *The above chart represents Alberta Storage Price Differentials derived from prices reported on the Natural Gas Exchange (NGX).*

Fluctuations in Storage Price Differentials affect ATCO Midstream's earnings and cash flow from operations. At current values, a $0.05 per gigajoule change in Storage Price Differentials impacts the Corporation's annual consolidated earnings attributable to equity owners of the Corporation, by approximately $2 million.

NGL Extraction Operations

A portion of ATCO Midstream's revenues is derived from the extraction of NGL from natural gas and the marketing of NGL products under sales contracts. ATCO Midstream owns a net working interest of 411 million cubic feet per day of processing capacity in its NGL extraction plants. Throughput for ATCO Midstream's NGL extraction operations was 360 mmcf/day for the three months ended March 31, 2012 compared to 400 mmcf/day for the comparative period in 2011. The reduction in throughput was largely due to increased competition for natural gas supply at some of ATCO Midstream's NGL facilities.

The majority of ATCO Midstream's NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the Frac Spread. Frac Spreads vary with fluctuations in the price of natural gas and the prices of the applicable liquids extracted. Frac Spreads can be volatile, as shown in the following graph, which illustrates monthly Frac Spreads during the period of December 2007 to March 2012.



(1) *The above chart represents measurements of industry Frac Spreads in Alberta as reported by an independent consultant. The average Frac Spreads for the three months ended March 31, 2012, were $10.12 per gigajoule compared to $10.48 per gigajoule for the three months ended March 31, 2011.*

Historically, fluctuations in Frac Spreads directly affected ATCO Midstream's earnings and cash flow from operations. More recently, owing to increased competition for natural gas supply, the positive effect from higher Frac Spreads is being partially offset by increased costs of obtaining natural gas for extraction. Therefore, a correlation of Frac Spreads to earnings cannot be made. Earnings from ATCO Midstream's NGL operations in 2012 were approximately the same as 2011.

ATCO Australia

For the three months ended March 31, 2012, ATCO Australia's revenues **increased** by $41 million (171%) over 2011 primarily due to the addition of ATCO Gas Australia, which was acquired on July 29, 2011.

Adjusted Earnings for ATCO Australia are shown in the following table:

	For the Three Months Ended March 31		
($ millions)	**2012**	2011	Change (2012-2011)
ATCO Gas Australia	**3**	-	3
ATCO Power Australia	**6**	6	-
Other [(1)]	**(3)**	(2)	(1)
	6	4	2

(1) *Other includes ATCO I-Tek Australia and ATCO Australia's Corporate Office.*

The results for ATCO Gas Australia will fluctuate due to the seasonal nature of demand for natural gas. Natural gas throughput is higher in the Australian winter months (July to September) compared to the summer months (December to February). This typically results in higher Adjusted Earnings in the second and third quarters compared to the first and fourth quarters.

Adjusted Earnings increased by $2 million (50%) for the three months ended March 31, 2012, over the corresponding period in 2011 mainly due to the addition of ATCO Gas Australia. This was partially offset by an increase in personnel and office costs due to the establishment and maintenance of the Perth head office as of the second quarter of 2011 and ongoing business development initiatives.

ATCO Power Australia

Availability of the generating plants in Australia for the three months ended March 31, 2012, was 98.4% compared to 99.8% in the corresponding period in 2011, a decrease of 1.4%.

Corporate & Other

Adjusted Earnings for the three months ended March 31, 2012, were $13 million, an **increase** of $6 million over the corresponding period in 2011. The increase was primarily due to lower income taxes pertaining to international financing arrangements, increased business activity in ATCO I-Tek and higher equity earnings from ATCO Structures & Logistics.

Liquidity and Capital Resources

A substantial portion of the Corporation's operating income and Funds Generated by Operations is generated from its utility operations. Canadian Utilities and its wholly owned subsidiary, CU Inc., use bank loans and commercial paper borrowings to provide flexibility in the timing and amounts of long term financing.

SUMMARY OF CASH FLOW

	For the Three Months Ended March 31		
($ millions)	**2012**	2011	Change (2012-2011)
Cash position, beginning of period	**613**	540	73
Cash provided by (used in)			
Operating activities:			
Funds Generated by Operations	**418**	383	35
Changes in non-cash working capital	**13**	37	(24)
Cash flow from operations	**431**	420	11
Investing activities	**(425)**	(202)	(223)
Financing activities	**(144)**	(99)	(45)
Foreign currency impact on cash balances	**-**	2	(2)
Cash position, end of period	**475**	661	(186)

OPERATING ACTIVITIES

For the three months ended March 31, 2012, **Funds Generated by Operations** were $418 million, an **increase** of $35 million (9%) over 2011. This increase was mainly due to higher earnings and contributions by utility customers for infrastructure. For the three months ended March 31, 2012, **cash flow from operations** was $431 million, an **increase** of $11 million (3%) over 2011. This increase was due to the higher Funds Generated by Operations, partially offset by a reduction in changes in non-cash working capital, which arose primarily because of lower customer receipts in ATCO Gas resulting from warmer weather in 2012.

INVESTING ACTIVITIES

For the three months ended March 31, 2012, **cash used in investing activities increased** by $223 million (110%) over 2011. This increase was mainly due to the increased capital investment in regulated distribution and transmission infrastructure projects in ATCO Electric, with the majority of the expenditures relating to the northeast transmission development project in the Fort McMurray region, partially offset by higher capital accounts payable in ATCO Electric.

Capital expenditures for the three months ended March 31, 2012, are shown in the following table:

	For the Three Months Ended March 31[1]		
($ millions)	**2012**	2011	Change (2012-2011)
Utilities			
Electric Transmission and Distribution	**431**	142	289
Gas Distribution	**56**	40	16
Pipeline Transmission	**12**	10	2
Energy	**4**	6	(2)
ATCO Australia	**11**	-	11
Corporate & Other	**3**	9	(6)
	517	207	310

(1) Includes additions to property, plant and equipment and intangibles and $12 million (2011 - $4 million) of interest capitalized during construction for the three months ended March 31, 2012.

FINANCING ACTIVITIES

In 2012, the Corporation had **repayments** of long term debt of $30 million. This was comprised of repayments of $20 million in ATCO Australia on its long term debt facilities and repayments of $10 million of non-recourse long term debt by ATCO Power and ATCO Power Australia.

On March 1, 2012, Canadian Utilities Limited commenced a new normal course issuer bid for the purchase of up to 3% of the outstanding Class A Shares. The bid will expire on February 28, 2013. From March 1, 2012 to April 25, 2012, no shares have been purchased.

Total **dividends** paid to Class A and Class B Share owners **increased** by $5 million to $56 million. In 2012, the **quarterly dividend** payment on the Corporation's Class A and Class B Shares was **increased** by $0.04 (10%) to $0.4425 per share over 2011. On April 11, 2012, the Board of Directors declared a second quarter dividend of $0.4425 per share. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

Share Capital

The equity securities of the Corporation consist of Class A Shares and Class B Shares.

At April 25, 2012, the Corporation had outstanding 87,271,933 Class A Shares, 40,359,249 Class B Shares, and options to purchase 617,900 Class A Shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

The owners of the Class A Shares and the Class B Shares are entitled to share equally, on a share for share basis, in all dividends declared by the Corporation on either of such classes of shares as well as the remaining property of the Corporation upon dissolution. The owners of the Class B Shares are entitled to vote and to exchange at any time each share held for one Class A Share.

If a take-over bid is made for the Class B Shares which would result in the offeror owning more than 50% of the outstanding Class B Shares and which would constitute a change in control of the Corporation, owners of Class A Shares are entitled, for the duration of the bid, to exchange their Class A Shares for Class B Shares and to tender such Class B Shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A Shares are entitled to exchange their shares for Class B Shares if ATCO Ltd., the controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B Shares. In either case, each Class A Share is exchangeable for one Class B Share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 6,400,000 Class A Shares authorized for grant in respect of options under the Corporation’s stock option plan, 2,869,200 Class A Shares were available for issuance at March 31, 2012. Options may be granted to officers and key employees of the Corporation and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of April 25, 2012, options to purchase 617,900 Class A Shares were outstanding.

Future Accounting Changes

Certain new or amended standards have been issued by the International Accounting Standards Board (IASB) that are not required to be adopted in the current period. These changes and amendments are substantially unchanged from those discussed in the 2011 MD&A. The Corporation has not early adopted these standards. There were no new or amended standards issued by the IASB in the first quarter of 2012 which the Corporation anticipates will have a material effect on the consolidated financial statements or note disclosures.

Internal Control Over Financial Reporting

There was no change in the Corporation’s internal control over financial reporting that occurred during the period beginning on January 1, 2012, and ended on March 31, 2012, that has materially affected, or is reasonably likely to materially affect, the Corporation’s internal control over financial reporting.

Non-GAAP and Additional GAAP Measures

The Corporation uses the measures "Funds Generated by Operations" and "Adjusted Earnings" in this MD&A. These measures do not have any standardized meaning under IFRS and might not be comparable to similar measures presented by other companies.

Funds Generated by Operations is defined as cash flow from operations before changes in non-cash working capital. In management's opinion, Funds Generated by Operations is a significant performance indicator of the Corporation's ability to generate cash during a period to fund its capital expenditures without regard to changes in non-cash working capital during the period.

Adjusted Earnings are defined as earnings attributable to equity owners of the Corporation after adjusting for the timing of revenues and expenses associated with rate regulated activities and dividends on equity preferred shares of the Corporation. Adjusted Earnings also exclude one-time gains and losses and items that are not in the normal course of business or day-to-day operations. Adjusted Earnings present earnings from rate regulated activities on the same basis as was used prior to adopting IFRS – that basis being the U.S. accounting principles for rate regulated activities. It is management's view that Adjusted Earnings allow for a more effective analysis of operating performance and trends. A reconciliation of Adjusted Earnings to earnings attributable to equity owners of the Corporation is presented in the Results of Operations section. Adjusted Earnings is an additional GAAP measure because it is presented in Note 3 to the 2012 Interim Financial Statements.

Forward-Looking Information

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Corporation believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

Glossary

Adjusted Earnings means earnings attributable to equity owners of the Corporation after adjusting for the timing of revenues and expenses associated with rate regulated activities and dividends on equity preferred shares of the Corporation. Adjusted Earnings also exclude one-time gains and losses and items that are not in the normal course of business or day-to-day operations. Refer to Importance of Adjusted Earnings section for a description of these items.

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

ATCO Structures & Logistics means ATCO Structures & Logistics Ltd.

AUC means the Alberta Utilities Commission.

Availability is a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Carbon Facility means ATCO Midstream's natural gas storage facility located at Carbon, Alberta.

Class A Shares means Class A non-voting shares of the Corporation.

Class B Shares means Class B common shares of the Corporation.

Corporation means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries.

Frac Spread means the premium or discount between the purchase price of natural gas and the selling price of extracted natural gas liquids on a heat content equivalent basis.

GAAP means Canadian generally accepted accounting principles.

Gigajoule (GJ) means a unit of energy equal to approximately 948.2 thousand British thermal units.

IFRS means International Financial Reporting Standards.

Megawatt (MW) is a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) means a measure of electricity consumption equal to the use of 1,000,000 watts of power over a one-hour period.

Mmcf/day means million cubic feet per day.

NGL means natural gas liquids, such as ethane, propane, butane and pentanes plus, that are extracted from natural gas and sold as distinct products or as a mix.

Propane Plus means propane, butane, pentane and other hydrocarbons other than methane and ethane.

Shrinkage Gas means the natural gas which is used to replace, on a heat equivalent basis, the NGL extracted during NGL extraction operations.

Spark Spread means the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, Spark Spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

Storage Price Differentials means seasonal differences (summer/winter) in the prices of natural gas.

U.K. means United Kingdom.

U.S. means United States of America.

Canadian Utilities Limited
Consolidated Statement of Earnings
(Millions of Canadian Dollars except per share data)

	Note		Three Months Ended March 31 2012		2011
Revenues			**837**		809
Costs and expenses					
Salaries, wages and benefits			**(112)**		(103)
Energy transmission and transportation			**(31)**		(11)
Plant and equipment maintenance			**(47)**		(37)
Fuel costs			**(80)**		(123)
Purchased power			**(16)**		(16)
Materials and consumables			**(9)**		(15)
Depreciation and amortization			**(102)**		(85)
Franchise fees			**(52)**		(62)
Other			**(75)**		(72)
			(524)		(524)
			313		285
Earnings from investment in ATCO Structures & Logistics			**7**		6
Operating profit			**320**		291
Interest income			**4**		5
Interest expense			**(66)**		(53)
Net finance costs			**(62)**		(48)
Earnings before income taxes			**258**		243
Income taxes			**(60)**		(61)
Earnings for the period			**198**		182
Earnings attributable to:					
Equity owners of the Corporation			**193**		176
Equity preferred share owners of subsidiary			**5**		6
			198		182
Earnings per Class A and Class B share	6	**$**	**1.45**	$	1.34
Diluted earnings per Class A and Class B share	6	**$**	**1.44**	$	1.33

See accompanying Notes to Consolidated Financial Statements.

Canadian Utilities Limited
Consolidated Statement of Comprehensive Income
(Millions of Canadian Dollars)

	Note	Three Months Ended March 31 2012	2011
Earnings for the period		**198**	182
Other comprehensive income (loss), net of income taxes:			
Retirement benefits[1]	7	**(24)**	2
Cash flow hedges[2]		**4**	-
Foreign currency translation adjustment[3]		**(4)**	-
		(24)	2
Comprehensive income for the period		**174**	184
Comprehensive income attributable to:			
Equity owners of the Corporation		**169**	178
Equity preferred share owners of subsidiary		**5**	6
		174	184

(1) *Net of income taxes of $8 million and $(1) million, respectively.*
(2) *Net of income taxes of $(1) million and nil, respectively.*
(3) *Net of income taxes of nil.*

See accompanying Notes to Consolidated Financial Statements.

Canadian Utilities Limited
Consolidated Balance Sheet
(Millions of Canadian Dollars)

	Note	**March 31 2012**	December 31 2011
ASSETS			
Current assets			
Cash and cash equivalents		**475**	613
Accounts receivable		**377**	421
Finance lease receivables		**15**	14
Inventories		**83**	82
Prepaid expenses and other current assets		**48**	52
		998	1,182
Non-current assets			
Property, plant and equipment	4	**9,868**	9,470
Intangibles		**290**	291
Investment in ATCO Structures & Logistics		**156**	152
Finance lease receivables		**526**	531
Other assets		**72**	70
Total assets		**11,910**	11,696
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities		**624**	542
Provisions		**42**	43
Other current liabilities		**14**	38
Long term debt		**139**	139
Non-recourse long term debt		**40**	40
		859	802
Non-current liabilities			
Deferred income tax liabilities		**466**	440
Provisions		**180**	187
Retirement benefit obligations	7	**413**	389
Long term debt		**4,189**	4,213
Non-recourse long term debt		**328**	338
Other liabilities		**1,188**	1,141
Total liabilities		**7,623**	7,510
EQUITY			
Equity preferred shares		**724**	724
Equity preferred shares of subsidiary corporation		**343**	343
Class A and Class B share owners' equity			
Class A and Class B shares	6	**621**	621
Contributed surplus		**-**	1
Retained earnings		**2,610**	2,508
Accumulated other comprehensive income (loss)		**(11)**	(11)
		3,220	3,119
Total equity		**4,287**	4,186
Total liabilities and equity		**11,910**	11,696

See accompanying Notes to Consolidated Financial Statements.

Canadian Utilities Limited
Consolidated Statement of Changes in Equity

(Millions of Canadian Dollars)

	Note	Class A and Class B Shares	Equity Preferred Shares [1]	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
At December 31, 2010		533	848	1	2,366	(10)	3,738
Earnings for the period		-	-	-	182	-	182
Shares issued, net of issue costs		83	-	-	-	-	83
Dividends	5	-	-	-	(63)	-	(63)
Share based compensation		-	-	(1)	(2)	-	(3)
Other comprehensive income (loss)		-	-	-	-	2	2
Gains (losses) on retirement benefits transferred to retained earnings		-	-	-	2	(2)	-
Transfer of ATCO Resources		-	-	-	(17)	-	(17)
At March 31, 2011		616	848	-	2,468	(10)	3,922
At December 31, 2011		**621**	**1,067**	**1**	**2,508**	**(11)**	**4,186**
Earnings for the period		**-**	**-**	**-**	**198**	**-**	**198**
Dividends	5	**-**	**-**	**-**	**(70)**	**-**	**(70)**
Share based compensation		**-**	**-**	**(1)**	**(2)**	**-**	**(3)**
Other comprehensive income (loss)		**-**	**-**	**-**	**-**	**(24)**	**(24)**
Gains (losses) on retirement benefits transferred to retained earnings		**-**	**-**	**-**	**(24)**	**24**	**-**
At March 31, 2012		**621**	**1,067**	**-**	**2,610**	**(11)**	**4,287**

[1] *Includes equity preferred shares and equity preferred shares of subsidiary corporation.*

See accompanying Notes to Consolidated Financial Statements.

Canadian Utilities Limited
Consolidated Statement of Cash Flows
(Millions of Canadian Dollars)

	Three Months Ended March 31	
	2012	2011
Operating activities		
Earnings for the period	**198**	182
Adjustments for:		
Depreciation and amortization	**102**	85
Earnings from investment in ATCO Structures & Logistics	**(7)**	(6)
Dividends received from ATCO Structures & Logistics	**2**	2
Income taxes	**60**	59
Unearned availability incentives	**10**	15
Contributions by customers for extensions to plant	**56**	24
Amortization of customer contributions	**(9)**	(9)
Net finance costs	**62**	48
Income taxes paid	**(53)**	(26)
Other	**(3)**	9
	418	383
Changes in non-cash working capital	**13**	37
Cash flow from operations	**431**	420
Investing activities		
Additions to property, plant and equipment	**(497)**	(191)
Additions to intangibles	**(8)**	(12)
Changes in non-cash working capital	**85**	(7)
Other	**(5)**	8
	(425)	(202)
Financing activities		
Repayment of long term debt	**(20)**	-
Repayment of non-recourse long term debt	**(10)**	(8)
Net issue of Class A shares	**2**	-
Dividends paid on equity preferred shares	**(9)**	(6)
Dividends paid on equity preferred shares of subsidiary	**(5)**	(6)
Dividends paid to Class A and Class B share owners	**(56)**	(51)
Interest paid	**(45)**	(30)
Other	**(1)**	2
	(144)	(99)
Foreign currency translation	**-**	2
Cash position [(1)]		
Increase (decrease)	**(138)**	121
Beginning of period	**613**	540
End of period	**475**	661

[(1)] *Cash position includes $27 million (2011 - $63 million) which is not available for general use by the Corporation.*

See accompanying Notes to Consolidated Financial Statements.

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. CORPORATE INFORMATION

Alberta-based Canadian Utilities Limited is engaged in utilities (pipelines, natural gas and electricity transmission and distribution), energy (power generation, natural gas gathering, processing, storage and liquids extraction) and technologies (business systems solutions). Canadian Utilities Limited is domiciled in Canada, and is listed on the Toronto Stock Exchange. Its registered office is at 1400, 909-11th Avenue SW, Calgary, Alberta, T2R 1N6. The Corporation is principally controlled by ATCO Ltd. and its controlling share owner, R.D. Southern.

The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments and an equity accounted for investment in ATCO Structures & Logistics (the "Corporation"). The consolidated financial statements were authorized for issue by the Audit Committee of the Board of Directors on April 26, 2012.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation and Consolidation

The accompanying condensed interim consolidated financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 *Interim Financial Reporting* using accounting policies consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the IFRS Interpretations Committee ("IFRIC"). They should be read in conjunction with the Corporation's consolidated financial statements for the year ended December 31, 2011 prepared in accordance with IFRS.

These interim consolidated financial statements have been prepared using the same accounting policies as used in the Corporation's consolidated financial statements for the year ended December 31, 2011, except for income taxes, which in interim periods, are accrued based on an estimate of the annualized effective tax rate applied to year to date taxable earnings. The policies applied in these interim consolidated financial statements are based on IFRS issued and effective as of April 26, 2012.

Due to certain factors, revenues, earnings and adjusted earnings for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the U.K., the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in natural gas liquids prices and natural gas costs, and the timing of rate decisions.

Certain comparative figures have been reclassified to conform to the current presentation.

Unless otherwise noted, tabular amounts are presented in millions of Canadian dollars.

3. SEGMENTED INFORMATION

Segmented Results – Three Months Ended March 31

2012 2011	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**516**	**236**	**65**	**20**	**-**	**837**
	468	298	24	19	-	809
Revenues – intersegment (1)	**1**	**-**	**-**	**36**	**(37)**	**-**
	6	2	-	31	(39)	-
Revenues	**517**	**236**	**65**	**56**	**(37)**	**837**
	474	300	24	50	(39)	809
Adjusted Earnings	**108**	**47**	**6**	**13**	**1**	**175**
	101	54	4	7	-	166
Total assets (2,3)	**8,337**	**1,836**	**1,320**	**638**	**(221)**	**11,910**
	7,903	1,891	1,340	728	(166)	11,696
Capital expenditures (4)	**499**	**4**	**11**	**3**	**-**	**517**
	192	6	-	9	-	207

(1) *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*
(2) *Total assets do not reflect adjustments for rate regulated activities included in Adjusted Earnings.*
(3) *2011 comparative total assets are as at December 31, 2011.*
(4) *Includes additions to property, plant and equipment and intangibles and $12 million (March 31, 2011 - $4 million) of interest capitalized during construction for the three months ended March 31, 2012.*

Reconciliation of Adjusted Earnings and Earnings – Three Months Ended March 31

2012 2011	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations	Consolidated
Adjusted Earnings	**108**	**47**	**6**	**13**	**1**	**175**
	101	54	4	7	-	166
Adjustments for rate regulated activities	**11** 3	**-** -	**(3)** -	**-** -	**1** 1	**9** 4
Dividends on equity preferred shares of Canadian Utilities Limited	**1** 1	**-** -	**-** -	**8** 5	**-** -	**9** 6
Earnings attributable to equity owners of the Corporation	**120** 105	**47** 54	**3** 4	**21** 12	**2** 1	**193** 176
Earnings attributable to equity preferred share owners of subsidiary						**5** 6
Earnings for the period						**198** 182

Adjusted Earnings

Adjusted Earnings are earnings attributable to equity owners of the Corporation after adjusting for the timing of revenues and expenses associated with rate regulated activities and dividends on equity preferred shares of the Corporation, as well as one-time gains and losses and items that are not in the normal course of business or a result of day to day operations. Adjusted Earnings are a key measure of

3. SEGMENTED INFORMATION (continued)

segment earnings used by the Chief Operating Decision Maker ("CODM") for purposes of assessing segment performance and allocating resources. Other accounts in the consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

Adjustments for Rate Regulated Activities

With respect to the accounting for rate regulated activities, prior to the adoption of IFRS, the Corporation had, as permitted by Canadian generally accepted accounting principles ("Canadian GAAP"), utilized standards issued by the Financial Accounting Standards Board ("FASB") in the United States ("U.S.") as another source of GAAP. The FASB standards provided guidance on the recognition and measurement of assets and liabilities arising from rate regulation where Canadian GAAP no longer provided such guidance. Adjusted Earnings presents earnings from rate regulated activities on the same basis as was used prior to adopting IFRS.

There is currently no specific guidance under IFRS for rate regulated entities. Consequently, the Corporation does not recognize assets and liabilities arising from rate regulated activities under IFRS.

The CODM is of the belief that earnings adjusted in accordance with the FASB standards are a better representation of the results of operations of its rate regulated activities. Furthermore, Adjusted Earnings facilitates comparability of the Corporation's financial results with rate regulated peer companies that have deferred the adoption of IFRS as permitted by the Canadian Accounting Standards Board, as well as with entities that utilize U.S. accounting principles for rate regulated entities.

Rate regulated accounting differs from IFRS in the following ways:

Rate Regulated Accounting Treatment	IFRS Treatment
(1) The Corporation was able to defer the recognition of cash received in advance of future expenditures.	The Corporation records revenues when amounts are billed to customers and recognizes costs when they are incurred.
(2) The Corporation was able to recognize revenues associated with recoverable costs in advance of future billings to customers.	The Corporation records costs when incurred, but does not recognize their recovery until changes to customer rates are reflected in future customer billings.
(3) The Corporation recognized the earnings that arose from a regulatory decision that pertained to current and prior periods upon receipt of the decision.	The Corporation recognizes earnings when customer rates are changed and amounts are billed to customers.
(4) Intercompany profits on the manufacture or construction of facilities for a regulated public utility in the consolidated group were deemed to have been realized to the extent that the transfer price on such facilities was recognized for rate-making purposes by a regulator.	Intercompany profits are eliminated upon consolidation. The Corporation then recognizes those profits in earnings as amounts are billed to customers over the life of the related asset.

3. SEGMENTED INFORMATION (continued)

Timing adjustments for rate regulated activities are as follows:

	Three Months Ended March 31	
	2012	2011
Additional revenues billed in current period:		
Future removal and site restoration costs [(1)]	**10**	12
Retirement benefits [(2)]	**6**	7
Transmission capital deferral [(5)]	**8**	3
Impact of colder temperatures on revenues [(7)]	**-**	9
Other	**8**	3
	32	34
Revenues to be billed in future period:		
Deferred income taxes [(3)]	**(17)**	(12)
Transmission access payments [(4)]	**(3)**	(4)
Transmission and distribution system load balancing [(6)]	**(2)**	(6)
Impact of warmer temperatures on revenues [(7)]	**(7)**	-
Impact of inflation on rate base for ATCO Gas Australia [(8)]	**(3)**	-
Other	**(1)**	(1)
	(33)	(23)
Regulatory decisions:		
Decisions related to current and prior periods [(9)]	**12**	(6)
Intercompany profits:		
Intercompany profits related to construction of property, plant and equipment and intangibles [(10)]	**(2)**	(1)
	9	4

Descriptions of the adjustments and the timing of recovery or refund for each are as follows:

Description	Timing of Recovery or Refund
(1) Forecast future removal and site restoration costs are billed to customers over the life of the associated assets in advance of future expenditures. Revenues are recorded when forecast costs are billed to customers. Costs will be expensed in future periods when incurred.	Differences between revenues received and costs incurred to date will reverse in future periods as actual removal and site restoration costs are incurred.
(2) The Corporation accrues for its obligations under defined benefit pension plans and other post employment benefit plans, whereas the costs of retirement benefits are recovered from customers when paid.	Variances between the amounts paid and accrued for the retirement benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will remain until the plans are paid, settled or terminated.

3. SEGMENTED INFORMATION (continued)

Description	Timing of Recovery or Refund
(3) Deferred income taxes are a non-cash expense incurred by the Corporation related to temporary differences between the book value and the tax value of assets and liabilities.	Deferred income taxes are not recovered from customers until the temporary differences reverse and current income taxes are paid by the Utilities, with the exception of federal deferred income taxes for ATCO Electric's transmission operations, which are recovered from customers effective January 1, 2011.
(4) ATCO Electric expenses transmission access payments when incurred, whereas the amount included in customer rates is based on forecast cost. Actual payments may vary from forecast due to changes in tariffs charged by the Alberta Electric System Operator ("AESO").	Recoveries from or refunds to customers of differences between transmission access payments billed to customers and paid by ATCO Electric are expected to occur in the next six to twelve months.
(5) For major transmission capital projects in Alberta, ATCO Electric's revenues include a return on forecast rate base. When actual capital costs vary from forecast capital costs, variances may arise between the returns on forecast versus actual rate base.	Recoveries from or refunds to the AESO of variances between forecast and actual returns on rate base are expected to occur in the following year.
(6) ATCO Gas and ATCO Pipelines engage in the purchase or sale of natural gas to maintain appropriate operating pressures on their distribution and transmission pipeline systems. The purchases and sales of natural gas are recorded as revenues when incurred. As a result of Alberta System integration with Nova Gas Transmission Limited ("NGTL"), effective October 1, 2011, ATCO Pipelines no longer purchases or sells natural gas to maintain operating pressures. This responsibility was transferred to NGTL.	ATCO Gas and ATCO Pipelines may apply to the Alberta Utilities Commission ("AUC") for recoveries from or refunds to customers of the net purchases and sales when they exceed certain thresholds: for ATCO Gas, $5 million over six successive months or $10 million for one month for either of its North or South systems; for ATCO Pipelines, $7 million for its North system and $5 million for its South system.
(7) ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the norm are refunded to or recovered from customers in future periods.	ATCO Gas may apply to the AUC for recoveries from or refunds to customers when the net revenue variances exceed $7 million at April 30th of any year for either of its North or South systems.

3. SEGMENTED INFORMATION (continued)

	Description	Timing of Recovery or Refund
(8)	Under the current access arrangement (January 1, 2010 to June 30, 2014), ATCO Gas Australia's rate base is adjusted by the rate of inflation measured by the Australian Eight Capital Cities Consumer Price Index. The impact of inflation on rate base is reflected in customer rates in future periods through the recovery of depreciation, whereas the inflation component is recognized in Adjusted Earnings at the time it is added to rate base.	The inflation-indexed portion of rate base will be recovered from customers over the life of the assets comprising rate base.
(9)	The Canadian and Australian utilities recognize revenues from regulatory decisions when customer rates are changed and amounts are billed to customers. Under Canadian GAAP, the utilities recognized the earnings that affected current and prior periods upon receipt of the decision.	Under IFRS, ATCO Gas' earnings from decisions related to the Carbon Storage Facility were recognized over a period of 14 months commencing in the fourth quarter of 2010 and ending December 31, 2011. In December 2011, ATCO Gas recorded a reduction in earnings of $10 million associated with a general rate application decision. Under IFRS, earnings will be adjusted once the AUC approves revised customer rates and the amount payable to customers is refunded through future billings. In December 2011, ATCO Electric received a decision approving the recovery of approximately $10 million over the period January 2012 to March 2012 associated with higher than forecast transmission access payments. Under IFRS, these revenues are recognized as customers are billed.
(10)	Intercompany profits included in property, plant and equipment and computer software by the utilities is eliminated upon consolidation.	The Corporation will recognize those intercompany profits in earnings as amounts are billed to customers over the life of the related asset.

4. PROPERTY, PLANT AND EQUIPMENT

	Utility Transmission & Distribution	Power Generation	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost:						
At December 31, 2011	9,520	2,219	315	763	834	13,651
Additions	**103**	**-**	**36**	**361**	**9**	**509**
Disposals	**(7)**	**(7)**	**-**	**-**	**(3)**	**(17)**
Changes to asset retirement costs	**-**	**(2)**	**-**	**-**	**(5)**	**(7)**
Foreign exchange adjustment	**(5)**	**2**	**-**	**-**	**-**	**(3)**
At March 31, 2012	**9,611**	**2,212**	**351**	**1,124**	**835**	**14,133**
Accumulated depreciation:						
At December 31, 2011	2,469	1,229	89	-	394	4,181
Depreciation	**63**	**18**	**2**	**-**	**14**	**97**
Disposals	**(7)**	**(5)**	**1**	**-**	**(3)**	**(14)**
Foreign exchange adjustment	**-**	**1**	**-**	**-**	**-**	**1**
At March 31, 2012	**2,525**	**1,243**	**92**	**-**	**405**	**4,265**
Net book value:						
At December 31, 2011	7,051	990	226	763	440	9,470
At March 31, 2012	**7,086**	**969**	**259**	**1,124**	**430**	**9,868**

Included in additions to property, plant and equipment is $12 million (March 31, 2011 - $4 million) of interest capitalized during construction for the three months ended March 31, 2012.

5. DIVIDENDS

Cash dividends declared and paid per share for all series and classes of preferred and common shares are as follows:

	Three Months Ended March 31	
	2012	2011
	(dollars per share)	
Equity preferred shares:		
4.35% Perpetual Cumulative Second Preferred Shares, Series O	**-**	0.271875
4.35% Perpetual Cumulative Second Preferred Shares, Series T	**-**	0.271875
4.35% Perpetual Cumulative Second Preferred Shares, Series U	**-**	0.271875
4.70% Perpetual Cumulative Second Preferred Shares, Series V	**0.29375**	0.29375
5.80% Cumulative Redeemable Second Preferred Shares, Series W	**0.3625**	0.3625
6.00% Cumulative Redeemable Second Preferred Shares, Series X	**0.3750**	0.3750
4.00% Cumulative Redeemable Second Preferred Shares, Series Y	**0.2500**	-
Class A and Class B shares	**0.4425**	0.4025

It is the policy of the Corporation to pay dividends quarterly on its Class A and Class B shares. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

6. CLASS A AND CLASS B SHARES AND EARNINGS PER SHARE

There were 87,271,933 (2011 – 87,072,150) Class A non-voting shares and 40,359,249 (2011 – 40,409,949) Class B common shares outstanding on March 31, 2012. In addition, there were 617,900 options to purchase Class A non-voting shares outstanding at March 31, 2012 under the Corporation's stock option plan. From April 1, 2012 to April 25, 2012, no stock options were granted, cancelled, or exercised, no Class B common shares were converted to Class A non-voting shares and no Class A non-voting shares were purchased under the Corporation's normal course issuer bid.

The earnings and average number of shares used to calculate earnings per share are as follows:

	Three Months Ended March 31	
	2012	2011
Average shares:		
Weighted average shares outstanding	**127,620,667**	127,466,347
Effect of dilutive stock options	**195,212**	170,849
Weighted average dilutive shares outstanding	**127,815,879**	127,637,196
Earnings for earnings per share calculation:		
Earnings for the period	**198**	182
Dividends on equity preferred shares of the Corporation	**(9)**	(6)
Dividends on equity preferred shares of subsidiary	**(5)**	(6)
	184	170
Earnings and diluted earnings per Class A and Class B share:		
Earnings per Class A and Class B share	**$1.45**	$1.34
Diluted earnings per Class A and Class B share	**$1.44**	$1.33

Normal course issuer bid

On March 1, 2012, Canadian Utilities Limited commenced a new normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid will expire on February 28, 2013. From March 1, 2012 to April 25, 2012, no shares have been purchased.

7. RETIREMENT BENEFITS

The discount rate assumption for the Corporation's accrued benefit obligation decreased from 5.2% at December 31, 2011 to 4.9% at March 31, 2012, resulting in an actuarial loss of $97 million (2011 – nil). There was no change in the discount rate assumption in the first quarter of 2011. The actuarial loss was partially offset by an experience gain on plan assets of $65 million for the three months ended March 31, 2012 (2011 – $3 million gain), resulting in a net loss on retirement benefit assets and obligations of $32 million (2011 - $3 million gain), which was recognized in other comprehensive income.

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EMERA INCORPORATED

Unaudited Condensed Consolidated Financial Statements

March 31, 2012 and 2011

Emera Incorporated
Consolidated Statements of Income (Unaudited)

For the millions of Canadian dollars (except per share amounts)	Three months ended March 31 **2012**	 2011
Operating revenues		
Regulated	**$ 526.1**	$ 507.5
Non-regulated	**41.9**	47.1
Total operating revenues	**568.0**	554.6
Operating expenses		
Regulated fuel for generation and purchased power	**218.1**	229.5
Regulated fuel and fixed cost adjustments (note 4)	**11.1**	(5.8)
Non-regulated fuel for generation and purchased power	**13.9**	20.7
Non-regulated direct costs	**14.3**	13.8
Operating, maintenance and general	**109.1**	111.5
Provincial, state, and municipal taxes	**12.5**	12.3
Depreciation and amortization	**63.0**	55.0
Total operating expenses	**442.0**	437.0
Income from operations	**126.0**	117.6
Income from equity investments	**6.0**	11.9
Other income (expenses), net (note 5)	**1.5**	41.6
Interest expense, net (note 6)	**41.9**	40.9
Income before provision for income taxes	**91.6**	130.2
Income tax expense (recovery) (note 7)	**6.8**	2.7
Net income	**84.8**	127.5
Non-controlling interest in subsidiaries	**2.9**	2.2
Net income of Emera Incorporated	**81.9**	125.3
Preferred stock dividends	**1.7**	1.7
Net income attributable to common shareholders	**$ 80.2**	$ 123.6
Weighted average shares of common stock outstanding (in millions)		
Basic	**123.6**	116.4
Diluted	**128.5**	121.8
Earnings per common share (note 8)		
Basic	**$ 0.65**	$ 1.06
Diluted	**$ 0.64**	$ 1.03
Dividends per common share declared	**$ 0.3375**	$ 0.3250

The accompanying notes are an integral part of these condensed consolidated financial statements.

Emera Incorporated
Consolidated Statements of Comprehensive Income (Unaudited)

For the millions of Canadian dollars	Three months ended March 31 **2012**	2011
Net income	**$ 84.8**	$ 127.5
Other comprehensive income (loss), net of tax		
Unrealized gains (losses) on cash flow hedges (1)	**(3.3)**	3.3
Hedging losses (gains) included in income (2)	**-**	0.5
Net change in unrecognized pension and post-retirement benefit recovery (costs) (3)	**9.5**	5.2
Unrealized gain (loss) on available-for-sale investment	**0.1**	-
Unrealized gain (loss) on translation of self-sustaining foreign operations (4)	**(20.6)**	(21.3)
Other comprehensive income (loss), net of tax (5)	**(14.3)**	(12.3)
Comprehensive income (loss)	**70.5**	115.2
Less: Comprehensive income (loss) attributable to non-controlling interest	**2.9**	2.2
Preferred stock dividends	**1.7**	1.7
Comprehensive income (loss) attributable to common shareholders	**$ 65.9**	$ 111.3

The accompanying notes are an integral part of these condensed consolidated financial statements.

1) Net of tax recovery of $2.8 million (2011 - $0.8 million tax expense) for the three months ended March 31, 2012.
2) Net of tax expense of $0.5 million (2011 - $0.7 million tax expense) for the three months ended March 31, 2012.
3) Net of tax expense of $1.3 million (2011 - $0.4 million tax recovery) for the three months ended March 31, 2012.
4) Net of tax expense/recovery of nil (2011 - nil tax expense/recovery) for the three months ended March 31, 2012.
5) Net of tax recovery of $1.0 million (2011 - $1.1 million tax expense) for the three months ended March 31, 2012.

Emera Incorporated
Consolidated Balance Sheets (Unaudited)

As at millions of Canadian dollars		**March 31 2012**		December 31 2011
Assets				
Current assets				
Cash and cash equivalents	**$**	**109.0**	$	76.9
Restricted cash		**11.0**		14.0
Receivables, net (note 9)		**458.7**		459.6
Income taxes receivable		**37.7**		41.6
Inventory (note 10)		**189.6**		198.8
Deferred income taxes		**14.5**		14.0
Derivative instruments (note 15 and 16)		**23.0**		27.3
Regulatory assets		**140.7**		141.6
Prepaid expenses		**29.1**		15.1
Other current assets		**5.7**		4.4
Total current assets		**1,019.0**		993.3
Property, plant and equipment, net of accumulated depreciation of **$2,876.2 and $2,838.0, respectively**		**4,320.4**		4,294.4
Other assets				
Deferred income taxes		**38.7**		33.1
Derivative instruments (note 15 and 16)		**32.4**		39.6
Regulatory assets		**338.7**		312.2
Net investment in direct financing lease		**491.6**		492.0
Investments subject to significant influence		**220.7**		222.7
Available-for-sale investments (note 11)		**58.0**		54.6
Goodwill		**194.3**		197.7
Intangibles, net of accumulated amortization of $61.2 and $59.7, respectively		**100.7**		100.7
Other		**150.2**		183.3
Total other assets		**1,625.3**		1,635.9
Total assets	**$**	**6,964.7**	$	6,923.6

The accompanying notes are an integral part of these condensed consolidated financial statements.

Emera Incorporated
Consolidated Balance Sheets (Unaudited) – Continued

As at millions of Canadian dollars		**March 31 2012**		December 31 2011
Liabilities and Equity				
Current liabilities				
Short-term debt	**$**	**199.4**	$	210.3
Current portion of long-term debt		**37.5**		35.7
Accounts payable		**262.6**		332.9
Income taxes payable		**1.1**		1.9
Deferred income taxes		**11.7**		10.9
Derivative instruments (note 15 and 16)		**56.6**		50.1
Regulatory liabilities		**21.2**		23.9
Pension and post-retirement liabilities (note 17)		**9.4**		8.8
Other current liabilities (note 13)		**146.3**		127.2
Total current liabilities		**745.8**		801.7
Long-term liabilities				
Long-term debt (note 14)		**3,316.8**		3,273.5
Deferred income taxes		**260.6**		228.6
Derivative instruments (note 15 and 16)		**34.0**		38.7
Regulatory liabilities		**99.9**		107.1
Asset retirement obligations		**99.0**		99.9
Pension and post-retirement liabilities (note 17)		**522.4**		530.8
Other long-term liabilities		**19.6**		19.6
Total long-term liabilities		**4,352.3**		4,298.2
Commitments and contingencies (note 18)				
Equity				
Common stock, no par value, unlimited shares authorized, 122.83 million and 123.49 million shares issued and outstanding, respectively (note 19)		**1,403.0**		1,385.0
Cumulative preferred stock, Series A, par value $25 per share; unlimited shares authorized, 6 million shares issued and outstanding		**146.7**		146.7
Contributed surplus		**3.2**		3.3
Accumulated other comprehensive loss		**(686.0)**		(671.7)
Retained earnings		**774.3**		735.9
Total Emera Incorporated equity		**1,641.2**		1,599.2
Non-controlling interest in subsidiaries		**225.4**		224.5
Total equity		**1,866.6**		1,823.7
Total liabilities and equity	**$**	**6,964.7**	$	6,923.6

The accompanying notes are an integral part of these condensed consolidated financial statements.

Approved on behalf of the Board of Directors

Chairman **President and Chief Executive Officer**

Emera Incorporated
Consolidated Statements of Cash Flows (Unaudited)

For the millions of Canadian dollars	Three months ended March 31 **2012**	2011
Operating activities		
Net income	**$ 84.8**	$ 127.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**66.7**	55.9
Income from equity investments, net of dividends	**(1.5)**	(7.6)
Allowance for equity funds used during construction	**(3.8)**	(2.4)
Deferred income taxes, net	**1.1**	9.2
Net change in pension and post-retirement, obligations (benefits)	**4.4**	0.7
Regulated fuel and fixed cost adjustments	**9.4**	(7.8)
Net change in fair value of derivative instruments	**(10.0)**	(2.6)
Net change in regulatory assets and liabilities	**(6.9)**	(2.9)
Other operating activities, net	**2.9**	(33.0)
Changes in non-cash working capital:		
Receivables, net	**(0.9)**	(33.4)
Income taxes receivable	**3.8**	(8.8)
Inventory	**8.6**	24.3
Prepaid expenses	**(14.1)**	(19.3)
Other current assets	**(0.7)**	(0.7)
Accounts payable	**(67.8)**	(37.7)
Income taxes payable	**(0.8)**	(1.6)
Other current liabilities	**19.8**	9.5
Net cash provided by operating activities	**95.0**	69.3
Investing activities		
Additions to property, plant and equipment	**(95.9)**	(66.0)
Acquisition, net of cash acquired	**-**	(35.1)
Decrease in restricted cash	**2.8**	54.1
Purchase of investments subject to significant influence, inclusive of acquisition costs	**-**	(33.5)
Allowance for borrowed funds used during construction	**(3.0)**	(2.3)
Retirement spending, net of salvage	**(1.9)**	(2.7)
Other investing activities	**29.2**	(57.1)
Net cash used in investing activities	**(68.8)**	(142.6)
Financing activities		
Change in short-term debt, net	**(10.8)**	48.2
Retirement of long-term debt	**(0.2)**	(0.4)
Proceeds from long term-debt	**365.6**	-
Net repayments under committed credit facilities	**(312.7)**	(64.1)
Issuance of common stock, net of issuance costs	**17.6**	203.2
Dividends on common stock	**(41.5)**	(37.3)
Dividends on preferred stock	**(1.6)**	(1.7)
Dividends paid by subsidiaries to non-controlling interest	**(2.0)**	(2.2)
Other financing activities	**(7.1)**	0.1
Net cash provided by financing activities	**7.3**	145.8
Effect of exchange rate changes on cash and cash equivalents	**(1.4)**	0.3
Net increase in cash and cash equivalents	**32.1**	72.8
Cash and cash equivalents, beginning of period	**76.9**	7.3
Cash and cash equivalents, end of period	**$ 109.0**	$ 80.1
Cash and cash equivalents consists of:		
Cash	**$ 78.1**	$ 46.3
Short-term investments	**30.9**	33.8
Cash and cash equivalents	**$ 109.0**	$ 80.1
Supplemental disclosure of cash paid (received):		
Interest	**$ 32.7**	$ 34.1
Income and capital taxes	**$ 3.2**	$ 3.1

The accompanying notes are an integral part of these condensed consolidated financial statements.

Emera Incorporated
Consolidated Statements of Changes in Equity (Unaudited)

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Loss ("AOCL")	Retained Earnings	Non-Controlling Interest	Total Equity
For the three months ended March 31, 2012							
Balance, December 31, 2011	$ 1,385.0	$ 146.7	$ 3.3	$ (671.7)	$ 735.9	$ 224.5	$ 1,823.7
Net income of Emera Incorporated	-	-	-	-	81.9	2.9	84.8
Other comprehensive income (loss), net of tax recovery of $1.0 million	-	-	-	(14.3)	-	-	(14.3)
Cash dividends declared on preferred stock ($0.2750/share)	-	-	-	-	(1.7)	-	(1.7)
Cash dividends declared on common stock ($0.3375/share)	-	-	-	-	(41.5)	-	(41.5)
Dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(0.2)	(0.2)
Common stock issued under purchase plan	11.5	-	-	-	-	-	11.5
Senior management stock options exercised	5.9	-	(0.5)	-	-	-	5.4
Stock option expense	-	-	0.4	-	-	-	0.4
Other stock-based compensation	0.6	-	-	-	(0.3)	-	0.3
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(2.0)	(2.0)
Other	-	-	-	-	-	0.2	0.2
Balance, March 31, 2012	$ 1,403.0	$ 146.7	$ 3.2	$ (686.0)	$ 774.3	$ 225.4	$ 1,866.6
For the three months ended March 31, 2011							
Balance, December 31, 2010	$ 1,137.8	$ 146.7	$ 3.2	$ (564.2)	$ 653.5	$ 154.4	$ 1,531.4
Net income of Emera Incorporated	-	-	-	-	125.3	2.2	127.5
Other comprehensive income (loss), net of tax expense of $1.1 million	-	-	-	(12.3)	-	-	(12.3)
Issuance of common stock, net of issuance costs	196.0	-	-	-	-	-	196.0
Additional Investment	-	-	-	-	-	59.7	59.7
Cash dividends declared on preferred stock ($0.2750/share)	-	-	-	-	(1.7)	-	(1.7)
Cash dividends declared on common stock ($0.3250/share)	-	-	-	-	(37.2)	-	(37.2)
Dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(0.2)	(0.2)
Common stock issued under purchase plan	9.0	-	-	-	-	-	9.0
Senior management stock options exercised	0.5	-	-	-	-	-	0.5
Stock option expense	-	-	0.2	-	-	-	0.2
Other stock-based compensation	0.3	-	-	-	(0.2)	-	0.1
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(2.0)	(2.0)
Balance, March 31, 2011	$ 1,343.6	$ 146.7	$ 3.4	$ (576.5)	$ 739.7	$ 214.1	$ 1,871.0

The accompanying notes are an integral part of these condensed consolidated financial statements.

Emera Incorporated
Notes to the Condensed Consolidated Financial Statements (Unaudited)

As at March 31, 2012 and 2011

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies for both the regulated and non-regulated operations of Emera Incorporated are as follows:

A. Nature of Operations

Emera Incorporated is an energy and services company which invests in electricity generation, transmission and distribution, gas transmission and utility energy services.

Emera's primary rate-regulated subsidiaries at March 31, 2012 included the following:

- Nova Scotia Power Inc. ("NSPI"), a fully-integrated electric utility and the primary electricity supplier in Nova Scotia serving approximately 494,000 customers;
- Bangor Hydro Electric Company ("Bangor Hydro") and Maine Public Service Company ("MPS"), which together provide transmission and distribution services to approximately 156,000 customers in Maine;
- an 80.0 percent interest in Light & Power Holdings Ltd. ("LPH"), the parent of The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated utility and sole provider of electricity on the island of Barbados serving approximately 123,000 customers;
- a 50.0 percent direct and 30.4 percent indirect interest (through ICD Utilities Limited ("ICDU")) in Grand Bahama Power Company Limited ("GBPC"), a vertically-integrated utility and sole provider of electricity on Grand Bahama Island serving approximately 19,000 customers; and
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145 kilometer pipeline carrying re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25 year firm service agreement with Repsol Energy Canada ("REC").

Emera Incorporated and its subsidiaries ("Emera" or the "Company") also own investments in other energy related companies, including:

- Emera Energy Services, a physical energy business which purchases and sells natural gas and electricity and provides related energy asset management services;
- Bayside Power Limited Partnership ("Bayside Power"), a 260-megawatt ("MW") electricity generating facility in Saint John, New Brunswick ;
- Emera Utility Services Inc. ("EUS"), a utility services contractor operating in Atlantic Canada and the Bahamas;
- a 50 percent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 600-MW pumped storage hydro-electric facility in northern Massachusetts;
- Emera Newfoundland & Labrador Holdings Inc. ("ENL"), a development project focused on transmission investments related to the proposed 824-MW hydro-electric generating facility at Muskrat Falls in Labrador, scheduled to be in service in 2017;
- a 12.9 percent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400 kilometer pipeline which transports natural gas from offshore Nova Scotia to markets in Maritime Canada and the northeastern United States;
- a 15.3 percent indirect interest, through LPH, in St. Lucia Electricity Services Limited ("Lucelec"), a vertically-integrated regulated electric utility on the Caribbean island of St. Lucia;
- a 49.999 percent interest in California Pacific Utilities Ventures, LLC, ("CPUV");
- a 5.8 percent investment in Algonquin Power & Utilities Corp ("APUC");
- a 37.7 percent investment in Atlantic Hydrogen Inc. ("AHI"); and
- other investments.

B. Basis of Presentation

These unaudited condensed consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP"). These unaudited condensed consolidated financial statements do not contain all disclosures required by USGAAP for annual audited financial statements. Accordingly, the financial statements should be read in conjunction with Emera Incorporated's annual audited financial statements as at and for the year ended December 31, 2011.

In the opinion of management, these unaudited condensed consolidated financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera Incorporated. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2012.

All dollar amounts are presented in Canadian dollars, unless otherwise indicated.

C. Principles of Consolidation

The consolidated financial statements of Emera Incorporated include the accounts of Emera Incorporated and its majority-owned subsidiaries, and a variable interest entity where Emera is the primary beneficiary. All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power.

Where Emera does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. The cost method of accounting is used for investments where Emera does not have significant influence over the operating and financial policies of the investee.

D. Use of Management Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an on-going basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Significant estimates are included in unbilled revenue, allowance for doubtful accounts, inventory, valuation of derivative instruments, depreciation, amortization, regulatory assets and regulatory liabilities (including the determination of the current portion), income taxes (including deferred income taxes), pension and post-retirement benefits, asset retirement obligations ("AROs") and contingencies. Actual results may differ significantly from these estimates.

E. Seasonal Nature of Operations

Interim results are not necessarily indicative of results for the full year primarily due to seasonal factors. Electricity sales and related generation vary significantly over the year; Q1 and Q4 are typically the strongest periods, reflecting colder weather and fewer daylight hours in the winter season in northeast North America, where a substantial portion of Emera's electricity business is located.

F. Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third party regulator; are designed to recover the costs of providing the regulated products or services;

and it is reasonable to assume rates are set at levels such that the costs can be charged to and collected from customers.

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates or tolls collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the appropriate regulator, or due to regulatory precedent set for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is as approved by the respective regulator.

G. Allowance for Funds Used During Construction

Allowance for Funds Used During Construction ("AFUDC") represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment. As approved by their respective regulator, NSPI, Bangor Hydro, MPS, GBPC, and Brunswick Pipeline include an equity cost component in AFUDC in addition to a charge for borrowed funds. AFUDC is a non-cash item; cash is realized under the rate-making process over the service life of the related property, plant and equipment through future revenues resulting from a higher rate base and recovery of higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to "Interest expense, net", while the equity component is included in "Other income (expenses), net". AFUDC is calculated using a weighted average cost of capital, as per the method of calculation approved by the respective regulator, and is compounded semi-annually. The annual AFUDC consisted of the following:

	2012			2011		
	Total	**Debt Component**	**Equity Component**	Total	Debt Component	Equity Component
NSPI	**7.97%**	**4.15%**	**3.82%**	7.87%	4.06%	3.81%
Bangor Hydro	**8.87%**	**2.55%**	**6.32%**	9.00%	2.60%	6.40%
MPS	**8.89%**	**2.87%**	**6.02%**	7.42%	2.37%	5.05%
GBPC	**10.00%**	**4.32%**	**5.68%**	10.00%	4.32%	5.68%

2. FUTURE ACCOUNTING PRONOUNCEMENTS

Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, Accounting Standards Update ("ASU") Number ("No.") 2011-11

In December 2011, The Financial Accounting Standards Board ("FASB") issued an accounting standards update which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU No. 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. The Company is currently evaluating the impact that the adoption will have in the financial statements.

3. SEGMENT INFORMATION

Emera is an energy and services company which invests in electricity generation, transmission and distribution, gas transmission and utility energy services. Emera manages its reportable segments separately due to their different geographical, operating and regulatory environments. Segments are reported based on each subsidiary's contribution of revenues, net income and total assets.

As at March 31, 2012, Emera has five reportable segments, specifically:

- NSPI;
- Maine Utility Operations (Bangor Hydro and MPS);
- Caribbean Utility Operations (BLPC, GBPC and Lucelec);
- Brunswick Pipeline; and
- Other (Emera Energy Services, EUS, M&NP, other strategic investments, holding companies, and inter-segment eliminations).

millions of Canadian dollars	NSPI	Maine Utility Operations	Caribbean Utility Operations	Brunswick Pipeline	Other and Eliminations	Total
For the three months ended March 31, 2012						
Operating revenues from external customers (1)	$ 360.7	$ 51.2	$ 101.6	$ 12.4	$ 30.5	$ 556.4
Inter-segment revenues (1)	0.2	-	-	-	11.4	11.6
Total operating revenues	360.9	51.2	101.6	12.4	41.9	568.0
Net income attributable to common shareholders	59.6	8.5	3.9	4.8	3.4	80.2
For the three months ended March 31, 2011						
Operating revenues from external customers (1)	$ 368.6	$ 52.5	$ 73.6	$ 12.4	$ 43.2	$ 550.3
Inter-segment revenues (1)	0.2	-	-	-	4.1	4.3
Total operating revenues	368.8	52.5	73.6	12.4	47.3	554.6
Net income attributable to common shareholders	63.6	9.4	29.6	4.7	16.3	123.6

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power. Eliminated transactions are included in determining reportable segments.

4. REGULATED FUEL AND FIXED COST ADJUSTMENTS

Regulated fuel and fixed cost adjustments consisted of the following:

For the millions of Canadian dollars	Three months ended March 31 **2012**	2011
Regulated Fuel Adjustment	**$ 22.1**	$ (5.8)
Regulated Fixed Cost Adjustment	**(11.0)**	-
	$ 11.1	$ (5.8)

Regulated Fuel Adjustment

The regulated fuel adjustment related to the fuel adjustment mechanism ("FAM") for NSPI includes the effect of fuel costs in both the current and two preceding years, specifically, and as detailed in the table below:

- The difference between actual fuel costs and amounts recovered from customers in the current year. This amount is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities".
- The recovery from (rebate to) customers of over (under) recovered costs from prior years.

For the millions of Canadian dollars		Three months ended March 31 **2012**		2011
Over (Under) recovery of current year fuel costs	**$**	**2.4**	$	(14.0)
Recovery from (Rebate to) customers of prior years' fuel costs		**19.7**		8.2
Regulated fuel adjustment	**$**	**22.1**	$	(5.8)

Since inception in 2009, the FAM was net of the incentive component, whereby NSPI retained or absorbed 10 percent of the over or under recovered amount to a maximum of $5 million. In November 2011, the UARB suspended the FAM incentive component for 2012 as part of the settlement agreement in the 2012 General Rate Application ("GRA") Decision.

In December 2011, the UARB approved NSPI's customer rates associated with the 2012 FAM adjustment related to the recovery of prior period fuel costs. The recovery of these costs began January 1, 2012. The approved customer rates seek to recover $69.0 million of prior years' unrecovered fuel costs in 2012.

As at March 31, 2012, the FAM regulatory asset was $73.2 million (December 31, 2011 - $93.7 million) and is classified in "Regulatory assets" on the Consolidated Balance Sheets. The FAM regulatory asset includes amounts recognized as a fuel adjustment and associated interest that is included in "Interest expense, net" " on the Consolidated Statements of Income.

NSPI has recognized a deferred income tax recovery related to the regulated fuel adjustment based on NSPI's enacted statutory tax rate. As at March 31, 2012, NSPI's deferred income tax liability related to the FAM was $22.7 million (December 31, 2011 - $29.0 million).

Regulated Fixed Cost Adjustment

The regulated fixed cost adjustment related to NSPI reflects the fixed cost recovery deferral ("FCR") as approved in the 2012 GRA Decision by the UARB for fiscal 2012. The FCR is intended to address uncertainty associated with the operations of two large industrial customers currently experiencing financial challenges. In the event that actual sales to these customers are less than expected when rates were set, the resultant shortfall in contribution toward non-fuel expenses will be deferred for future recovery. The FCR is effective January 1, 2012, and the recovery from customers will be determined in Q4 2012 through a GRA or FAM proceeding.

As at March 31, 2012, the FCR was $11.1 million (December 31, 2011 – nil) and is classified in "Regulatory assets" on the Consolidated Balance Sheets. The FCR regulatory asset includes amounts recognized as a fixed cost adjustment and associated interest that is included in "Interest expense, net" on the Consolidated Statements of Income.

NSPI has recognized a deferred income tax expense related to the FCR based on NSPI's enacted statutory tax rate. As at March 31, 2012, NSPI's deferred income tax liability related to the FCR was $3.4 million (December 31, 2011 – nil).

5. OTHER INCOME (EXPENSES), NET

Other income (expenses), net consisted of the following:

For the millions of Canadian dollars	Three months ended March 31 **2012**	2011
Gain on business acquisition (1)	**$ -**	$ 28.2
Gain on exchange of subscription receipts to common shares of APUC (2)	**-**	15.1
Allowance for equity funds used during construction	**3.8**	2.4
Amortization of defeasance costs	**(3.0)**	(3.0)
Foreign exchange gains (losses)	**0.2**	(0.4)
Foreign exchange gains (losses) recovered through the FAM	**(0.4)**	(1.3)
Other	**0.9**	0.6
	$ 1.5	$ 41.6

(1) Emera's interest in LPH was acquired in two tranches in Q2 2010 and Q1 2011 giving rise to non-taxable gains.

(2) Pursuant to an April 2009 subscription agreement with APUC, on January 1, 2011, Emera exchanged subscription receipts it acquired in 2009 into 8.523 million APUC common shares issued at $3.25 per share, resulting in a gain of $15.1 million (after-tax gain of $12.8 million).

6. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars	Three months ended March 31 **2012**	2011
Interest on debt (1)	**$ 45.2**	$ 43.7
Allowance for borrowed funds used during construction	**(3.0)**	(2.3)
Interest revenue	**(2.0)**	(2.1)
Other	**1.7**	1.6
	$ 41.9	$ 40.9

(1) Interest debt includes amortization of debt financing costs, premiums and discounts.

7. INCOME TAXES

Income tax expense for the three months ended March 31, 2012 was $6.8 million (2011 - $2.7 million). Income taxes are higher in 2012 compared to 2011 primarily due to decreased accelerated tax deductions related to property, plant and equipment, partially offset by increased tax deductions related to pension and a decrease to income before the provision of taxes.

The Company’s effective tax rate for the three months ended March 31, 2012 and March 31, 2011 was 7.4 percent and 2.1 percent, respectively. The effective tax rates for the three months ended March 31, 2012 and March 31, 2011 were lower than the 2012 and 2011 statutory income tax rates of 31.0 percent and 32.5 percent, respectively, primarily due to the effect of deferred income taxes on regulated income being deferred to regulatory assets and regulatory liabilities and therefore not affecting tax expense.

8. EARNINGS PER SHARE

The following table reconciles the computation of basic and diluted earnings per share:

For the millions of Canadian dollars (except per share amounts)		Three months ended March 31 **2012**		2011
Numerator				
Net income attributable to common shareholders	**$**	**80.2**	$	123.6
Preferred stock dividends of subsidiary		**2.0**		2.0
Diluted numerator		**82.2**		125.6
Denominator				
Weighted average shares of common stock outstanding		**123.0**		115.9
Weighted average DSUs outstanding		**0.6**		0.5
Weighted average shares of common stock outstanding – basic		**123.6**		116.4
Effect of dilutive securities		**4.0**		4.3
Stock-based compensation and employee common share purchase plan		**0.9**		1.1
Weighted average shares of common stock outstanding – diluted		**128.5**		121.8
Earnings per common share				
Basic	**$**	**0.65**	$	1.06
Diluted (1)	**$**	**0.64**	$	1.03

(1) The calculation of diluted earnings per share for the three months ended March 31, 2012 excluded the impact of nil (2011 – $0.2 million) of unexercised stock options that had an anti-dilutive effect.

9. RECEIVABLES, NET

Receivables, net consisted of the following:

As at millions of Canadian dollars		**March 31 2012**		December 31 2011
Customer accounts receivable – billed	**$**	**298.7**	$	310.7
Customer accounts receivable – unbilled		**131.3**		133.6
Total customer accounts receivable		**430.0**		444.3
Allowance for doubtful accounts		**(14.0)**		(12.8)
Customer accounts receivable, net		**416.0**		431.5
Other		**42.7**		28.1
	$	**458.7**	$	459.6

10. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars		**March 31 2012**		December 31 2011
Fuel	**$**	**123.4**	$	134.6
Materials		**66.2**		64.2
	$	**189.6**	$	198.8

11. AVAILABLE-FOR-SALE INVESTMENTS

The available-for-sale investments consist primarily of investments in debt and equity securities held in trust on behalf of BLPC's SIF for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmissions and distribution systems. The SIF Fund assets are not available to the Company for use in its operations.

Emera has classified these investments as available-for-sale and recorded all such investments at their fair market value as at March 31, 2012.

Available-for-sale financial assets include the following:

As at millions of Canadian dollars		**March 31 2012**		December 31 2011
Common shares	**$**	**4.3**	$	1.3
Mutual funds		**19.5**		17.8
Corporate bonds, debentures, short and medium term notes		**26.6**		27.7
Government bonds		**7.6**		7.8
	$	**58.0**	$	54.6

The change in available-for-sale assets is as follows:

As at millions of Canadian dollars		**March 31 2012**		December 31 2011
Balance, beginning of the year	**$**	**54.6**	$	0.8
Resulting from acquisitions		**-**		53.5
Additions, net of foreign exchange loss		**3.9**		36.5
Disposals		**(0.5)**		(35.8)
	$	**58.0**	$	55.0
Change in fair value				
Loss (Gain) recognized in regulatory liability		**0.7**		(0.1)
Gain (Loss) recognized in other comprehensive income during the period		**(0.7)**		(0.3)
	$	**-**	$	(0.4)
Balance, end of the period	**$**	**58.0**	$	54.6

There were no impairment provisions for available-for-sale investments for the three months ended March 31 2012 or the year ended December 31, 2011.

The maturity profile of debt securities included in the available-for-for-sale assets is as follows:

As at millions of Canadian dollars		**March 31 2012**		December 31 2011
Maturity within 1 year	**$**	**10.4**	$	12.7
Maturity in 1-5 years		**23.8**		22.8
	$	**34.2**	$	35.5

The maximum exposure to credit risk at the reporting date is the carrying value of the debt securities. None of these financial instruments are either past due or impaired.

12. ACQUISITIONS

Light & Power Holdings Ltd.

On January 25, 2011, Emera acquired 7.2 million shares of LPH, the parent company of BLPC, a vertically-integrated utility and the sole provider of electricity on the island of Barbados with a franchise to produce, transmit and distribute electricity on the island until 2028, for total cash consideration of $92.6 million CAD ($92.8 million USD). As a result, Emera became the majority shareholder of LPH, with a total interest of 80.1 percent. This investment was made to increase Emera's regulated transmission, distribution and generation portfolio.

Prior to this transaction, Emera owned 38.3 percent of LPH with a carrying value of $113.5 million CAD ($113.8 million USD). The fair value of Emera's interest in LPH immediately prior to the acquisition date was $84.8 million CAD ($85.0 million USD).

The fair value of the assets of a regulated utility are generally deemed to equal book value (rate base) given the regulated utility's earnings are a function of its rate base, as determined by the regulator. The purchase price was negotiated between arms-length parties. The differential between the two amounts resulted in Emera recording a gain on acquisition of $ 28.2 million, which Emera has recorded as a non-taxable gain in “Other income (expenses), net” on Emera’s Consolidated Statements of Income for the year ended December 31, 2011.

The valuation technique used to measure the acquisition-date fair value of the assets and liabilities of LPH was book value for regulated assets given the regulatory environment in which BLPC operates. Non-regulated assets were measured based on recent transactions. Accordingly, a third party valuation of assets and liabilities was not performed.

The purchase price allocation has been finalized. The total purchase price has been allocated to the fair value of assets and liabilities as follows:

	millions of Canadian dollars	
Cash and cash equivalents	$	58.4
Restricted cash		12.3
Receivables, net		23.4
Income tax receivable		0.2
Inventory		16.3
Prepaid expenses		2.9
Property, plant and equipment		292.0
Available-for-sale investments		52.5
Other non-current assets		1.6
Current portion of long-term debt		(7.5)
Account payable		(33.7)
Other current liabilities		(5.3)
Long-term debt		(43.1)
Deferred income taxes		(9.5)
Regulatory liabilities		(62.7)
ARO		(2.2)
Other long-term liabilities		(2.5)
Gain on business acquisition (1)		(28.2)
Non-controlling interest		(58.2)
Total purchase consideration	$	206.7

(1) The gain shown above represents the net effect of the gain on acquisition of $56.3 million net of a loss of $28.1 million on a business combination achieved in stages, which requires the revaluation of the existing interest to the implied value from the second investment at the date of acquiring control. The gain is included in “Other income (expenses) net” in the Consolidated Statements of Income.

The Company has included operating revenues of $282.4 million and net income attributable to common shareholders of $12.0 million for BLPC in its consolidated net income attributable to common shareholders for fiscal 2011 related to the period subsequent to January 25, 2011.

The Company also incurred $2.0 million in acquisition-related costs of which $0.5 million was recorded in 2010 and $1.5 million was recorded in 2011. These costs are included in “Operating, maintenance and general expense” in the Consolidated Statements of Income.

13. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars		**March 31** **2012**		December 31 2011
Accrued charges	**$**	**62.8**	$	69.0
Accrued interest on long-term debt		**49.8**		38.0
Sales taxes payable		**24.1**		12.8
Dividends payable		**2.0**		2.0
Other		**7.6**		5.4
	$	**146.3**	$	127.2

14. LONG-TERM DEBT

GBPC

On January 25, 2012, GBPC entered into an unsecured credit agreement with Scotiabank (Bahamas) Limited in the amount of $56.2 million USD. The proceeds of the credit agreement will be used to finance the construction of a 52-MW power plant on Grand Bahama Island. The credit agreement bears interest at a rate of the three month LIBOR rate plus 1.2 percent and is repayable in forty equal, consecutive quarterly installments over a ten year period. The payments commence at the earlier of six months after the completion of the construction of the power plant or January 31, 2013.

Bangor Hydro

On January 31, 2012, Bangor Hydro completed the issuance of an unsecured $70.0 million USD senior note. The Series 2012-A Senior Note bears interest at a rate of 3.61 percent per annum until January 31, 2022. The net proceeds of the note offering were used to repay borrowings under the revolving credit facility.

LPH

On February 9, 2012, LPH entered into a secured credit agreement with The Bank of Nova Scotia in the amount of USD $14.2 million. The proceeds of the credit agreement were used to partially finance the purchase of a 19.1 percent interest in Lucelec from a wholly-owned subsidiary of Emera. The credit agreement bears interest at a rate of the three month LIBOR plus 1.05 percent and is repayable in six equal, consecutive semi-annual installments over a three year period. The payments commence six months after the initial drawdown. LPH has provided a cash deposit of $14.2 million ($28.4 million Barbadian dollars) and an unlimited guarantee as security for the credit agreement.

NSPI

On March 6, 2012, NSPI completed the issuance of $250 million Series Y Medium-Term Notes. The Series Y Notes bear interest at a rate of 4.15 percent per annum until March 5, 2042. The net proceeds of the note offering were used to repay short-term borrowings and for general corporate purposes.

15. DERIVATIVE INSTRUMENTS

The Company enters into futures, forwards, swaps and option contracts as part of its risk management strategy to limit exposure to:

- commodity price fluctuations related to the purchase and sale of commodities in the course of normal operations;
- foreign exchange fluctuations on foreign currency denominated purchases and sales; and
- interest rate fluctuations on debt securities.

The Company also enters into physical contracts for energy commodities. Collectively, these contracts are considered "derivatives". The Company accounts for derivatives under one of the following four approaches:

1. Physical contracts that meet the normal purchases normal sales ("NPNS") exception are not recognized on the balance sheet; they are recognized in income when they settle. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives that qualify for hedge accounting are recorded at fair value on the balance sheet. Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge the identified cash flow risk both at the inception and over the term of the derivative. Specifically for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to AOCL and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in fair value from cash flow hedges is recognized in net income in the reporting period.

   Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value with any changes in fair value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

3. Derivatives entered into by NSPI, that are documented as economic hedges, and for which the NPNS exception has not been taken, receive regulatory deferral as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized when the derivatives settle. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

4. Derivatives that do not meet any of the above criteria are designated as Held-for-trading ("HFT") and are recognized on the balance sheet at fair value. All gains and losses are recognized in net income of the period. The Company has not elected to designate any derivatives to be included in the HFT category when another accounting treatment applies.

Derivative assets and liabilities relating to the foregoing categories consisted of the following:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**March 31 2012**	**December 31 2011**	**March 31 2012**	**December 31 2011**
Current				
Cash flow hedges				
Power & gas swaps	**$ -**	$ -	**$ 6.4**	$ 8.1
Foreign exchange forwards	**3.0**	2.7	**0.5**	0.5
	3.0	2.7	**6.9**	8.6
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**5.2**	5.4	**0.1**	0.1
Natural gas purchases and sales	**-**	0.7	**39.0**	33.5
Foreign exchange forwards	**2.7**	6.0	**2.5**	-
Physical natural gas purchases and sales	**4.2**	4.2	**0.4**	0.1
	12.1	16.3	**42.0**	33.7
HFT derivatives				
Power swaps and physical contracts	**2.5**	1.4	**1.8**	1.2
Natural gas swaps, futures, forwards and physical contracts	**7.2**	10.9	**7.7**	10.6
	9.7	12.3	**9.5**	11.8
Total gross current derivatives	**24.8**	31.3	**58.4**	54.1
Impact of master netting agreements with intent to settle net or simultaneously	**(1.8)**	(4.0)	**(1.8)**	(4.0)
Total current derivatives	**23.0**	27.3	**56.6**	50.1
Long-term				
Cash flow hedges				
Power swaps	**0.4**	0.2	**10.0**	12.8
Interest rate swaps	**-**	-	**5.7**	6.2
Foreign exchange forwards	**2.9**	2.8	**0.3**	0.2
	3.3	3.0	**16.0**	19.2
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**5.3**	6.7	**-**	-
Natural gas purchases and sales	**-**	-	**5.2**	5.1
Foreign exchange forwards	**15.1**	18.2	**7.6**	7.9
Physical natural gas purchases and sales	**2.3**	3.7	**-**	-
	22.7	28.6	**12.8**	13.0
HFT derivatives				
Power swaps and physical contracts	**0.9**	0.9	**0.6**	0.8
Natural gas swaps, futures, forwards and physical contracts	**7.0**	6.8	**6.1**	5.4
	7.9	7.7	**6.7**	6.2
Total gross long-term derivatives	**33.9**	39.3	**35.5**	38.4
Impact of master netting agreements with intent to settle net or simultaneously	**(1.5)**	0.3	**(1.5)**	0.3
Total long-term derivatives	**32.4**	39.6	**34.0**	38.7
Total derivatives	**$ 55.4**	$ 66.9	**$ 90.6**	$ 88.8

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Cash Flow Hedges

The Company enters into various derivatives designated as cash flow hedges. Emera enters into power swaps to limit Bear Swamp's exposure to purchased power prices. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams and capital projects denominated in foreign currency for Brunswick Pipeline and Bayside Power, respectively. MPS entered into an interest rate swap to hedge the fluctuation in interest rates on long-term debt.

As previously noted, the effective portion of the change in fair value of these derivatives is included in AOCL, until the hedged transactions are recognized in income. The ineffective portion is recognized in income of the period. The following table shows the amounts related to cash flow hedges recorded in AOCL and income for the period:

For the millions of Canadian dollars	Three months ended March 31 **2012**			Three months ended March 31 2011		
	Power and Gas Swaps	**Interest Rate Swaps**	**Foreign Exchange Forwards**	Power and Gas Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Unrealized gain (loss) in non-regulated fuel and purchased power – ineffective portion	**$ (0.1)**	**$ -**	**$ -**	$ (0.6)	$ -	$ -
Realized gain (loss) in non-regulated fuel and purchased power	**(2.0)**	**-**	**-**	(1.0)	-	-
Realized gain (loss) in regulated operating revenue	**-**	**-**	**0.8**	-	-	0.8
Realized gain (loss) in other income, (expenses), net	**-**	**-**	**(0.2)**	-	-	(0.1)
Total gains (losses) in income	**$ (2.1)**	**$ -**	**$ 0.6**	$ (1.6)	$ -	$ 0.7
Total unrealized gain (loss) in AOCL – effective portion, net of tax	**$ (4.9)**	**$ 0.1**	**$ 0.4**	$ 1.0	$ 0.2	$ 1.6

The Company expects $8.6 million of unrealized losses currently in AOCL to be reclassified into net income within the next twelve months, as the underlying hedged transactions settle.

As at March 31, 2012, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	**2012**	2013	2014	2015	2016	2017
Power swaps (megawatt hours ("MWh")) purchases	**0.3**	0.3	0.3	0.3	0.3	0.3
Gas swaps (Mmbtu) purchases	**2.7**	-	-	-	-	-
Foreign exchange forwards (EURO) purchases	**9.6**	-	-	2.8	-	-
Foreign exchange forwards (USD) sales	**$ 40.6**	$ 48.0	$ 15.0	$ 9.0	$ 6.0	$ -

In addition, the Company has interest rate swaps on long-term debt of $13.6 million until 2021 and $9.0 million until 2025.

Regulatory Deferral

As previously noted, NSPI receives approval from the UARB for regulatory deferral of gains and losses on certain derivatives documented as economic hedges, including certain physical contracts that do not qualify for the NPNS exemption.

The Company has recorded the following realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

For the three months ended millions of Canadian dollars	Regulatory Assets **March 31 2012**	 March 31 2011	Regulatory Liabilities **March 31 2012**	 March 31 2011
Current				
Commodity swaps and forwards				
Coal purchases	**$ -**	$ (1.0)	**$ 0.3**	$ (0.6)
Natural gas purchases and sales	**5.7**	(8.8)	**0.4**	(1.5)
Heavy Fuel Oil ("HFO") purchases	**-**	(1.3)	**-**	1.9
Foreign exchange forwards	**2.5**	3.2	**3.2**	2.0
Physical natural gas purchases and sales	**0.4**	0.1	**-**	(0.3)
Long-term				
Commodity swaps and forwards				
Coal purchases	**-**	-	**1.4**	(2.9)
Natural gas purchases and sales	**0.1**	(1.5)	**-**	(0.1)
Foreign exchange forwards	**(0.3)**	10.5	**3.1**	2.2
Physical natural gas purchases and sales	**-**	-	**1.4**	1.2

Regulatory Impact Recognized in Net Income

The Company recognized the following gains (losses) related to derivatives receiving regulatory deferral as follows:

For the millions of Canadian dollars	Three months ended March 31 **2012**	 2011
Regulated fuel for generation and purchased power	**$ (9.4)**	$ (15.6)
Net gains (losses)	**$ (9.4)**	$ (15.6)

Commodity Swaps and Forwards

As at March 31, 2012, the Company had the following notional volumes of outstanding commodity swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

millions	**2012** Purchases	2013 Purchases	2014 Purchases
Coal (metric tonnes)	**0.4**	0.3	0.1
Natural gas (Mmbtu)	**15.4**	13.2	0.5

Foreign Exchange Swaps and Forwards

As at March 31, 2012, the Company had the following notional volumes of foreign exchange swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2012	2013	2014	2015	2016
Fuel purchases exposure (millions of US dollars)	**$ 177.0**	$ 212.0	$ 210.0	$ 210.0	$ 120.0
Weighted average rate	**0.9923**	1.0251	1.0106	1.0090	0.9814
% of USD requirements	**73.8%**	70.4%	66.0%	66.0%	37.7%

Held-for-Trading Derivatives

In the ordinary course of its business, Emera enters into physical contracts for the purchase and sale of natural gas; and power and natural gas swaps, forwards, and futures to economically hedge those physical contracts. These derivatives are all considered HFT.

The Company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives:

For the millions of Canadian dollars	Three months ended March 31 **2012**	2011
Power swaps and physical contracts in non-regulated operating revenues	**$ 0.1**	$ (1.0)
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**4.9**	7.6
Foreign exchange forwards in other income (expenses), net	**-**	0.3
	$ 5.0	$ 6.9

As at March 31, 2012, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2012	2013	2014	2015	2016	2017
Natural gas purchases (Mmbtu)	**71.1**	**45.6**	**29.8**	**22.4**	**5.8**	**0.4**
Natural gas sales (Mmbtu)	**37.4**	**20.4**	**7.3**	**1.8**	**-**	**-**
Power purchases (MWh)	**0.5**	**-**	**-**	**-**	**-**	**-**
Power sales (MWh)	**0.5**	**-**	**-**	**-**	**-**	**-**

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties and deposits or collateral are requested on any high risk accounts.

The Company assesses the potential for credit losses on a regular basis, and where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements ("ISDA"), North American Energy Standards Board agreements ("NAESB") and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

Cash Collateral

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables, net" and obligations to return cash collateral are recognized in "Accounts payable".

The Company's cash collateral positions consisted of the following:

As at millions of Canadian dollars		**March 31** **2012**		December 31 2011
Cash collateral provided to others	**$**	**46.1**	$	71.6
Cash collateral received from others		**10.4**		5.7

Collateral is posted in the normal course of business based on the Company's creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company's derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt to fall below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at March 31, 2012, the total fair value of these derivatives, in a net liability position, is $ 90.6 million (December 31, 2011 – $ 88.8 million). If the credit ratings of the Company were reduced below investment grade the full value of the net liability position could be required to be posted as collateral for these derivatives.

16. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception (see note 15), and uses a market approach to do so. The three levels of the fair value hierarchy are defined as follows:

Level 1 Valuations - Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 Valuations - Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 Valuations - Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following tables set out the classification of the methodology used by the Company to fair value its derivatives:

As at				March 31, 2012
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash flow hedges				
Power and gas swaps	**$ 0.4**	**$ -**	**$ -**	**$ 0.4**
Foreign exchange forwards	**-**	**5.9**	**-**	**5.9**
	0.4	**5.9**	**-**	**6.3**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**10.5**	**-**	**10.5**
Foreign exchange forwards	**-**	**17.8**	**-**	**17.8**
Physical natural gas purchases and sales	**-**	**-**	**6.4**	**6.4**
	-	**28.3**	**6.4**	**34.7**
HFT derivatives				
Power swaps and physical contracts	**-**	**-**	**2.4**	**2.4**
Natural gas swaps, futures, forwards and physical contracts	**-**	**9.8**	**2.2**	**12.0**
	-	**9.8**	**4.6**	**14.4**
Total assets	**0.4**	**44.0**	**11.0**	**55.4**
Liabilities				
Cash flow hedges				
Power and gas swaps	**16.4**	**-**	**-**	**16.4**
Foreign exchange forwards	**-**	**0.8**	**-**	**0.8**
Interest rate swaps	**-**	**5.7**	**-**	**5.7**
	16.4	**6.5**	**-**	**22.9**
Regulatory deferral				
Commodity swaps and forwards				
Natural gas purchases and sales	**44.2**	**-**	**-**	**44.2**
Foreign exchange forwards	**-**	**10.1**	**-**	**10.1**
Physical natural gas purchases and sales	**-**	**-**	**0.4**	**0.4**
	44.2	**10.1**	**0.4**	**54.7**
HFT derivatives				
Power swaps and physical contracts	**0.2**	**-**	**1.3**	**1.5**
Natural gas swaps, futures, forwards and physical contracts	**3.0**	**7.6**	**0.9**	**11.5**
	3.2	**7.6**	**2.2**	**13.0**
Total liabilities	**63.8**	**24.2**	**2.6**	**90.6**
Net assets (liabilities)	**$ (63.4)**	**$ 19.8**	**$ 8.4**	**$ (35.2)**

As at				**December 31, 2011**
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power and gas swaps	$ 0.2	$ -	$ -	$ 0.2
Foreign exchange forwards	-	5.5	-	5.5
	0.2	5.5	-	5.7
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	12.1	-	12.1
Natural gas purchases and sales	(0.4)	0.7	-	0.3
HFO purchases	-	24.2	-	24.2
Physical natural gas purchases and sales	-	-	7.9	7.9
	(0.4)	37.0	7.9	44.5
HFT derivatives				
Power swaps and physical contracts	0.3	-	1.6	1.9
Natural gas swaps, futures, forwards and physical contracts	-	10.4	4.4	14.8
	0.3	10.4	6.0	16.7
Total assets	0.1	52.9	13.9	66.9

As at				December 31, 2011
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Liabilities				
Cash flow hedges				
Power and gas swaps	$ 20.9	$ -	$ -	$ 20.9
Foreign exchange forwards	-	0.7	-	0.7
Interest rate swaps	-	6.2	-	6.2
	20.9	6.9	-	27.8
Regulatory deferral				
Commodity swaps and forwards				
Natural gas purchases and sales	38.3	-	-	38.3
Foreign exchange forwards	-	7.9	-	7.9
Physical natural gas purchases and sales	-	-	0.1	0.1
	38.3	7.9	0.1	46.3
HFT derivatives				
Power swaps and physical contracts	0.3	-	1.3	1.6
Natural gas swaps, futures, forwards and physical contracts	2.7	7.3	3.1	13.1
	3.0	7.3	4.4	14.7
Total liabilities	62.2	22.1	4.5	88.8
Net assets (liabilities)	$ (62.1)	$ 30.8	$ 9.4	$ (21.9)

The change in the fair value of the Level 3 financial assets for the three months ended March 31 was as follows:

	Regulatory Deferral	*Trading Derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1	**$ 7.9**	**$ 1.6**	**$ 4.4**	**$ 13.9**
Increase (Reduction) in benefit included in regulated fuel for generation and purchased power	**(0.8)**	**-**	**-**	**(0.8)**
Unrealized gains (losses) included in regulatory assets or liabilities	**(0.7)**	**-**	**-**	**(0.7)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**0.8**	**(2.2)**	**(1.4)**
Balance, March 31	**$ 6.4**	**$ 2.4**	**$ 2.2**	**$ 11.0**

The change in the fair value of the Level 3 financial liabilities for the three months ended March 31 was as follows:

	Regulatory deferral	*Trading derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1	**$ 0.1**	**$ 1.3**	**$ 3.1**	**$ 4.5**
Increase (Reduction) in benefit included in regulated fuel for generation and purchased power	**(0.1)**	**-**	**-**	**(0.1)**
Unrealized gains (losses) included in regulatory assets or liabilities	**0.4**	**-**	**-**	**0.4**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**-**	**(2.2)**	**(2.2)**
Balance, March 31	**$ 0.4**	**$ 1.3**	**$ 0.9**	**$ 2.6**

The significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives includes third-party-sourced-pricing for instruments based on illiquid markets; internally developed correlation factors and basis differentials; probabilities of default; and discount rates. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement.

The following table outlines quantitative information about the significant unobservable inputs used in the fair value measurements categorized within Level 3 of the fair value hierarchy:

As at					**March 31, 2012**
millions of Canadian dollars	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets					
Regulatory deferral – Physical natural gas purchases and sales	**$ 6.4**	Modeled pricing	Third-party pricing	$2.32 - $6.95	$3.91
			Probability of default	0.07% - 0.64%	0.23%
HFT derivatives – Power swaps and physical contracts	**1.3**	Modeled pricing	Third-party pricing	$23.70- $51.72	$33.23
			Probability of default	0.14% - 0.17%	0.15%
			Discount rate	0.00% - 2.68%	0.32%
	1.1	Modeled pricing	Third-party pricing	$18.8 - $50.68	$32.85
			Correlation factor	0.96% - 1.00%	0.98%
			Probability of default	0.17% - 0.52%	0.17%
			Discount rate	0.00% - 2.68%	0.74%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**1.2**	Modeled pricing	Third-party pricing	$2.32 - $4.31	$3.10
			Probability of default	0.05% - 26.72%	1.19%
			Discount rate	0.00% - 0.80%	0.09%
	1.0	Modeled pricing	Third-party pricing	$2.10 - $5.29	$2.67
			Basis adjustment	(0.06%) - 0.36%	(0.03%)
			Probability of default	0.09% - 1.17%	0.61%
			Discount rate	0.00% - 1.15%	0.13%
Total assets	**11.0**				
Liabilities					
Regulatory deferral – Physical natural gas purchases and sales	**0.4**	Modeled pricing	Third-party pricing	$2.32 - $2.64	$2.52
			Own credit risk	-	0.17%
HFT derivatives – Power swaps and physical contracts	**1.3**	Modeled pricing	Third-party pricing	$23.70 - $51.72	$33.25
			Own credit risk	-	0.17%
			Discount rate	0.00% - 2.68%	0.32%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**0.6**	Modeled pricing	Third-party pricing	$2.42 - $7.00	$5.13
			Own credit risk	-	0.17%
			Discount rate	0.00% - 2.30%	0.37%
	0.3	Modeled pricing	Third-party pricing	$2.10 - $3.31	$2.54
			Basis adjustment	(0.06%) - 0.36%	(0.05%)
			Own credit risk	-	0.17%
			Discount rate	0.00% - 1.15%	0.11%
Total liabilities	**2.6**				
Net assets (liabilities)	**$ 8.4**				

The financial assets and liabilities included on the Consolidated Balance Sheets that are not measured at fair value consisted of the following:

As at	**March 31, 2012**		December 31, 2011	
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term debt (including current portion)	**$ 3,354.3**	**$ 3,939.2**	$ 3,309.2	$ 3,935.0

The fair values of long-term debt instruments, classified as level 3 in the fair value hierarchy, are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturity, without considering the effect of third party credit enhancements.

All other financial assets and liabilities such as cash and cash equivalents, restricted cash, accounts receivable, short-term debt and accounts payable are carried at cost. The carrying value approximates fair value due to the short-term nature of these financial instruments.

17. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees; and plans providing non-pension benefits for its retirees in Nova Scotia, Maine, Barbados and Grand Bahama Island.

Net periodic costs prior to the effects of capitalization consisted of the following:

For the	Three months ended March 31	
millions of Canadian dollars	**2012**	2011
Defined benefit pension plans		
Service cost	**$ 4.5**	$ 4.1
Interest cost	**14.2**	14.2
Expected return on plan assets	**(14.5)**	(12.6)
Current year amortization of:		
Actuarial losses (gains)	**8.1**	6.1
Special termination benefits	**1.6**	-
Total defined benefit pension plans	**13.9**	11.8
Non-pension benefits plan		
Service cost	**0.7**	0.7
Interest cost	**1.2**	1.2
Current year amortization of:		
Actuarial losses (gains)	**0.6**	0.4
Past service costs (gains)	**(0.4)**	(0.4)
Special termination benefits	**0.6**	-
Total non-pension benefits plans	**2.7**	1.9
Total defined benefit plans	**$ 16.6**	$ 13.7

Emera's contributions related to these defined benefit plans for the three months ended March 31, 2012 were $13.8 million (2011 - $12.4 million). In addition, the Company contributions related to the defined contribution plan for the three months ended March 31, 2012 were $0.7 million (2011 - $0.8 million).

18. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at March 31, 2012, commitments (excluding pensions and other post-retirement benefits, long-term debt, and AROs) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2012	2013	2014	2015	2016	Thereafter	Total
Purchased power (1)	**$ 85.5**	$ 108.8	$ 109.0	$ 117.3	$ 117.5	$ 1,343.2	$ 1,881.3
Coal, biomass, oil and natural gas supply	**153.6**	139.6	103.8	58.6	22.4	599.9	$ 1,077.9
Transportation (2)	**54.5**	31.3	28.8	16.3	2.2	2.7	$ 135.8
Long-term service agreements (3)	**10.5**	11.5	6.4	5.0	0.5	0.5	$ 34.4
Capital projects	**57.1**	3.5	0.6	3.9	-	-	$ 65.1
Leases (4)	**2.3**	3.2	3.3	3.2	2.8	16.0	$ 30.8
Other	**4.7**	3.5	3.3	3.2	1.3	1.0	$ 17.0
Total	**$ 368.2**	$ 301.4	$ 255.2	$ 207.5	$ 146.7	$ 1,963.3	$ 3,242.3

(1) Purchased power: annual requirement to purchase 100 percent of electricity production from independent power producers.

(2) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on various pipelines.

(3) Long-term service agreements: outsourced management of the Company's computer and communication infrastructure, vegetation management and maintenance of certain generating equipment.

(4) Leases: operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

B. Legal Proceedings

A number of individuals who live in proximity to the NSPI's Trenton generating station have filed a statement of claim for an unspecified amount against NSPI in respect of emissions from the operation of the plant for the period from 2001 forward. The plaintiffs claim unspecified damages as a result of interference with enjoyment of, or damage to, their property. NSPI has filed a defense to the claim. The outcome of this litigation, and therefore an estimate of any contingent loss, is not determinable.

On October 31, 2011, MF Global Holding Ltd., the parent company of MF Global Inc. ("MFG"), a futures commission merchant used by Emera Energy Services ("Emera Energy") for natural gas and electricity futures filed for Chapter 11 bankruptcy. Emera Energy was able to transfer its open future positions to other brokers; however $5.46 million USD of its posted margin was frozen with MFG and Emera Energy was unable to transfer these funds. Legal proceedings related to the bankruptcy have been initiated and are expected to involve cross-border insolvency proceedings as a result of MFG's global affiliates. Although management expects to recover the majority of the frozen funds, a provision has been recognized and the net amount has been reclassified to "Other long-term assets". The outcome of the bankruptcy proceedings is currently not determinable.

In addition, Emera and its subsidiaries may, from time to time, be involved in legal proceedings, claims and litigations that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Environment

Emera's activities are subject to a broad range of federal, provincial, state, regional and local laws and environmental regulations, designed to protect, restore, and enhance the quality of the environment including air, water and solid waste. Emera estimates its environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations will be approximately $60.6 million during 2012 and are estimated to be $273.3 million from 2013 through 2016. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 18A. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies may be enacted in response to issues such as climate change and other pollutant emissions.

NSPI

NSPI is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters primarily through its utility operations. In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to NSPI. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on NSPI.

Conformance with legislative and NSPI requirements are verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits to date.

Climate Change and Air Emissions

Greenhouse Gas Emissions

NSPI has stabilized, and in recent years, reduced greenhouse gas emissions. This has been achieved by energy efficiency and conservation programs, increased use of natural gas and the addition of new renewable energy sources to the generation portfolio.

Greenhouse gas emissions from NSPI facilities have been capped beginning in 2010 through to 2020. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Over the decade, the caps will be achieved by a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

In 2011, Environment Canada announced proposed regulations for a new national carbon dioxide framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units; and existing coal-fired electricity generation units that have reached the end of their deemed economic life of forty-five years after commissioning. These proposed regulations will be effective July 1, 2015. Nova Scotia's existing greenhouse gas regulations require reductions in NSPI's emissions similar to those reflected in the federal framework.

On March 19, 2012, Environment Canada and the Nova Scotia Environment Department announced they are working toward an equivalency agreement on coal-fired electricity greenhouse gas regulations to avoid duplication of efforts to control greenhouse gas emissions. In the equivalency agreement, provincial regulations would take precedence over federal regulations, provided provincial regulations achieve an equivalent emissions outcome.

Nova Scotia’s existing greenhouse gas regulations require reductions of 25 percent in greenhouse gas emission in the electricity sector by 2020. The Province of Nova Scotia plans to develop additional more stringent milestones between 2020 and 2030 to match the federal targets. Discussions are underway for the 2020 to 2030 period to ensure consistency with the proposed federal regulations. NSPI is reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Renewable Energy

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI’s generation mix. The target date for 5 percent of electricity to be supplied from post-2001 sources of renewable energy, owned by independent power producers, was extended to 2011 from 2010. The target for 2013, which requires an additional 5 percent of renewable energy, is unchanged at a total of 20 percent renewable energy including NSPI owned and pre-2001 sources.

On May 19, 2011 the Nova Scotia Government approved The Electricity Act (Amended) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25 percent in 2015, to 40 percent by 2020.

Mercury, Nitrogen Oxide and Sulphur Dioxide Emissions

NSPI completed a capital program to add sorbent injection to each of the seven pulverized fuel coal units in 2010 at a cost of $17.3 million. This was put in place to address planned reductions in mercury emissions limits, which are set out in the following table:

Year	Mercury Emissions Limit (kg)
2009	168
2010	110
2011 - 2012	100
2013	85
2014 - 2019	65
2020	35

Any mercury emission above 65 kg, between 2010 and 2013, must be offset by lower emissions in the 2014 to 2020 period.

NSPI completed its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units in early 2009 at a cost of $23.3 million. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the Nova Scotia Government effective 2010. These investments, combined with the purchasing of low sulfur coal, allow NSPI to meet the provincial air quality regulations.

NSPI is committed to meeting ever-reducing sulphur dioxide emission cap requirements through the use of a blend of net lower sulphur content solid fuel.

Compared to historical levels, NSPI will have reduced mercury emissions by 60 percent effective 2014, nitrogen oxide by 40 percent effective 2009 and sulphur dioxide by 50 percent effective 2010.

Poly Chlorinated Bi-Phenol Transformers

In response to the Canadian Environmental Protection Act 1999, 2008 Poly Chlorinated Bi-Phenol ("PCB") Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other oil filled electrical equipment on its system that do not meet the 2008 PCB Regulations Standard by 2014. In addition, there is a project to phase out the use of pole mount transformers before 2025 including a capital program to destroy all confirmed PCB contaminated pole mount transformers taken out of service through attrition. The combined total cost of these projects is estimated to be $35.0 million and, as at March 31, 2012, approximately $8.1 million (December 31, 2011 - $7.8 million) has been spent to date. NSPI has recognized an ARO of $18.8 million as at March 31, 2012 (December 31, 2011 - $20.6 million) associated with the PCB phase-out program.

Maine Utilities

Poly Chlorinated Bi-Phenol Transformers

In response to a Maine environmental regulation to phase out PCB transformers, the Maine Utilities implemented multi-year programs to eliminate transformers on their systems that do not meet the new State environmental guidelines. The Maine Utilities completed their programs in 2011. The cost of testing the transformers is expensed as incurred; replacement transformers and the cost to install those transformers are capitalized. As of December 31, 2011 all transformers were remediated and are PCB-free in this effort; the total cumulative expenditures associated with the Maine Utilities' programs was $4.4 million.

Caribbean Utilities

The Caribbean utilities have implemented a Health Safety Environmental and Management system to assist in safeguarding the health and safety of employees, contractors and customers while ensuring protection of the environment.

D. Principal Risks and Uncertainties

In this section, Emera describes some of the principal risks management believes could materially affect Emera's business, revenues, operating income, net income, net asset or liquidity or capital resources. The nature of risk is such that no list can be comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach.

Regulatory Risk

The Company's rate-regulated subsidiaries are subject to risk in the recovery of costs and investments in a timely manner. The Company manages this regulatory risk through transparent regulatory disclosure, ongoing stakeholder consultation and multi-party engagement on aspects such as utility operations, rate filings and capital plans.

Changes in Environmental Legislation

The Company is subject to regulation by federal, provincial, state, regional, and local authorities with regard to environmental matters primarily related to its utility operations. Changes to climate change and air emissions standards could adversely affect utility operations.

Emera is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and Company policy. Emera and its wholly-owned subsidiaries have implemented this policy through development and application of environmental management systems.

Commodity Prices and Foreign Exchange Rate Fluctuations

A substantial amount of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts. In addition, the adoption and implementation of FAMs in certain subsidiaries has further helped manage this risk.

The Company enters into foreign exchange forward and swap contracts to limit exposure on foreign currency transactions such as fuel purchases and USD revenue streams.

Acquisition Risk

The risks associated with Emera's acquisition strategy include the availability of suitable acquisition candidates, obtaining the necessary regulatory approval for any acquisition and assimilating and integrating acquired companies into the Company. In addition, potential difficulties inherent in acquisitions may adversely affect the results of an acquisition. These include delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies from completed transactions.

Emera mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

Commercial relationships

NSPI

For the three months ended March 31, 2012, NSPI's five largest customers contributed approximately 6.5 percent (2011 – 13.1 percent) of electric revenues. The loss of a large customer could have a material effect on NSPI's operating revenues. NSPI works to mitigate this risk through operational adjustments and cost management as well as the regulatory process.

A large customer was granted creditor protection under the Companies' Creditors Arrangement Act ("CCAA"), and suspended operations in September 2011. NSPI is working to recover an outstanding balance of $11.6 million through the CCAA claims process, including a claim for set-off against amounts owing from NSPI to the customer that exceeds the amount receivable. The 2012 GRA Decision, approved by the UARB, provided for a FCR adjustment which allows NSPI to defer any unrecovered contribution toward non-fuel expenses in 2012 related to this customer. The recovery period will be determined through a GRA or FAM proceeding in Q4 2012.

Brunswick Pipeline

Brunswick Pipeline has a 25 year firm service agreement with Repsol Energy Canada ("REC"). The pipeline was used solely in 2012 and 2011 to transport natural gas from the Canaport LNG terminal in Saint John, New Brunswick to the United States border for REC. The risk of non-payment is mitigated as Repsol YPF, S.A ("Repsol"), the parent company of REC, has provided Brunswick Pipeline with a guarantee for all RECs' payment obligations under the firm service agreement. As at March 31, 2012 the net investment in direct financing lease with Repsol was $493.4 million. Credit ratings and other company information are monitored on an ongoing basis. On March 14, 2012, Moody's downgraded Repsol to Baa2 from Baa1; and on April 19, 2012, Standard & Poor's downgraded Repsol to BBB- from BBB, with a negative outlook. The rating agency actions have had no impact on the operations of the Canaport facility, nor REC's ability to meet its obligations under the firm service agreement.

Bayside Power

Bayside Power sells all of its power during the winter months, November through March, to NB Power in accordance with a long-term purchase power agreement ("PPA"). Revenue from this PPA contributed 100.0 percent (2011 – 100.0 percent) to Bayside Power's electric revenues for the three months ended March 31, 2012. The PPA expires March 31, 2021, with an option to renew for an additional five year term, provided both parties consent to the renewal.

Labour Risk

Certain Emera employees are subject to collective labour agreements. Approximately 53 percent of the full-time and term employees at NSPI, BLPC, GBPC, Bangor Hydro, EUS, and MPS are represented by local unions. Approximately 40 percent of the labour force is covered by collective labour agreements that have or will expire within the next twelve months. Where collective labour agreements have expired, negotiations for new agreements have commenced and are ongoing. Emera seeks to manage this risk through ongoing discussions with local unions.

Weather Risk

Shifts in weather patterns affect electric sales volumes and associated revenues. Extreme weather events generally result in increased operating costs associated with restoring power to customers. Emera responds to significant weather event related outages according to each subsidiary's respective Emergency Services Restoration Plan.

Interest Rate Risk

The Company utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

E. Collaborative Arrangement

Bangor Hydro

Through Bangor Hydro, the Company is a party to a collaborative arrangement with National Grid Transmission Services Corporation to develop the Northeast Energy Link ("NEL") Project. The cost of development activities, including acquisition of land in the transmission corridor and acquisition of necessary governmental and regulatory permits and approvals, are shared equally between the Company and National Grid. Bangor Hydro has deferred $2.5 million USD of costs associated with the NEL project as at March 31, 2012 (December 31, 2011 - $2.5 million USD), reported in the Consolidated Balance Sheets in “Other” as part of other assets.

F. Guarantees and Letters of Credit

Emera had the following guarantees and letter of credits as at March 31, 2012:

- NSPI has provided a limited guarantee for the indebtedness of Renewable Energy Services Ltd. (“RESL”). The guarantee is up to a maximum of $23.5 million. As at March 31, 2012, RESL’s indebtedness under the loan agreement was $21.6 million. NSPI holds a security interest in the present and future assets of RESL. For further information see note 21.

- Emera has provided a guarantee to the Long Island Power Authority (“LIPA”) on behalf of Bear Swamp for Bear Swamp’s long-term energy and capacity supply agreement (“PPA”) with LIPA, which expires on April 30, 2021. The guarantee is for 50 percent of the relevant obligations under the PPA up to a maximum of $18.6 million USD. As at March 31, 2012, the fair value of the PPA was positive.

- Emera has provided a guarantee to the Bank of Nova Scotia on behalf of Bear Swamp for Bear Swamp’s interest rate swaps entered into between Bear Swamp and the Bank of Nova Scotia which expires on May 9, 2012. The guarantee is for 50 percent of the relevant obligations up to a maximum of $1.0 million USD. In the event Emera was required to make a payment to the Bank of Nova Scotia under this guarantee, the guarantee provides that Emera is able to seek recovery from Bear Swamp’s creditors after Bear Swamp has paid its debts in full. As at March 31, 2012, the fair value of that agreement was positive.

- At the request of Emera and its subsidiaries, a financial institution has issued standby letters of credit in the amount of $10.5 million for the benefit of third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one year term and are renewed annually as required.

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2012 and is renewed annually. The amount committed as at March 31, 2012 was $22.5 million.

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in Bangor Hydro. The letter is renewed annually in October. The amount committed as at March 31, 2012 was $2.2 million USD.

- A financial institution has issued a standby letter of credit in connection with a precedent transmission line agreement between Bangor Hydro and two other parties. The letter of credit expires in December 2012. The amount committed as at March 31, 2012 was $1.75 million USD.

- A financial institution has been issued direct pay letters of credit totaling $23.9 million USD to secure principal and interest payments related to Maine Public Utilities Financing Bank bonds issued on behalf of MPS, related to qualifying distribution assets.

No liability has been recognized on the consolidated balance sheet related to any potential obligation under these guarantees and letters of credits.

19. COMMON STOCK

Authorized: Unlimited number of non-par value common shares.

Issued and outstanding:	millions of shares	millions of Canadian dollars	
Balance, December 31, 2011	122.83	$	1,385.0
Issued for cash under Purchase Plans at market rate	0.36		12.0
Discount on shares purchased under Dividend Reinvestment Plan	-		(0.5)
Options exercised under senior management share option plan	0.30		5.9
Stock-based compensation	-		0.6
Balance, March 31, 2012	**123.49**	**$**	**1,403.0**

20. RELATED PARTY TRANSACTIONS

MN&P

In the ordinary course of business, Emera purchased natural gas transportation capacity from M&NP, an investment under significant influence of the Company, totaling $7.6 million (2011 – $12.9 million) for the three months ended March 31, 2012. The amount is recognized in “Regulated fuel for generation and purchased power” or netted against energy marketing margin in “Non-regulated operating revenues” and is measured at the exchange amount. As at March 31, 2012, the amount payable to the related party was $2.5 million (December 31, 2011 – $3.3 million), and is under normal interest and credit terms.

Lucelec

On January 31, 2012, a wholly-owned subsidiary of Emera sold its 19.1 percent interest in Lucelec to LPH at book value, a subsidiary owned 80.0 percent by Emera, for $26.2 million ($29.1 million USD) effective January 1, 2012.

APUC

As at March 31, 2012 subscription receipts received and promissory notes issued to APUC were $98.8 million (December 31, 2011 - $135.8 million) included in “Other” assets and “Long-term debt” respectively on Emera’s Consolidated Balance Sheets.

On January 27, 2012, APUC announced it would not be proceeding with its investment to partner with Emera and First Wind Holdings LLC to own 370 MW of wind energy in the northeastern United States. In connection with this transaction, Emera had purchased 6.9 million subscription receipts for $5.37 each on July 29, 2011. With APUC’s subsequent withdrawal from the First Wind investment in Q1 2012, both the subscription receipts and related promissory note were cancelled.

21. VARIABLE INTEREST ENTITIES

The Company performs ongoing analysis to assess whether it holds any variable interest entities (“VIEs”). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where Emera is not deemed the primary beneficiary, the VIE is not recorded in the Company’s consolidated financial statements.

LPH has established a self-insurance fund (“SIF”) primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems.

LPH holds a variable interest in the SIF for which it was determined that LPH was the primary beneficiary and, accordingly, the SIF must be consolidated by LPH. In its determination that LPH controls the SIF, management considered that in substance the activities of the SIF are being conducted on behalf of LPH's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because LPH, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF.

NSPI holds a variable interest in RESL, a VIE for which it was determined that NSPI was not the primary beneficiary since it does not have the controlling financial interest of RESL. NSPI has provided a $23.5 million guarantee with no set term for the indebtedness of RESL under a loan agreement between RESL and a third party lender, in support of which NSPI holds a security interest in all present and future assets of RESL. The guarantee arose in conjunction with NSPI's participation in a wind energy project at Point Tupper, Nova Scotia, which is being operated by RESL. Under a purchased power agreement, NSPI purchases, at a fixed price, 100 percent of the power generated by the project. A default by RESL, under its loan agreement, would require NSPI to make payment under the guarantee. As at March 31, 2012, RESL's indebtedness under the loan agreement was $21.6 million (December 31, 2011 – $21.9 million), and NSPI has not recorded a liability in relation to the guarantee.

Bangor Hydro holds a variable interest in Chester Static Var Compensator ("SVC"), a VIE for which it was determined that Bangor Hydro was not the primary beneficiary since it does not have the controlling financial interest of Chester SVC. A subsidiary of Bangor Hydro is a 50 percent general partner in Chester SVC, which owns electrical equipment that supports a major transmission line. A wholly-owned subsidiary of Central Maine Power Company owns the other 50 percent interest. Chester SVC is 100 percent debt financed and accordingly the partners have no equity interest; and the holders of the SVC notes are without recourse against the partners or their parent companies.

The Company has identified certain long-term purchase power agreements that could be defined as variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

Emera's consolidated VIE is recorded as an "Available-for-sale investment". The following table provides information about Emera's consolidated and unconsolidated VIEs:

As at	**March 31, 2012**		December 31, 2011	
millions of Canadian dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Consolidated VIE				
BLPC SIF Available-for-sale investment	**$ 57.4**	**$ 57.4**	$ 54.1	$ 54.1
Unconsolidated VIEs in which Emera has Variable Interests				
RESL	**-**	**23.5**	-	23.5
Chester SVC	**-**	**-**	-	-

For the three months ended March 31, 2012, the Company has not identified any new VIEs.

22. COMPARATIVE INFORMATION

Effective Q1, 2012, the Company reclassified partnership income tax expense of $0.4 million previously recorded as a reduction in "Income from equity investments" to "Income tax expense (recovery)" in the Consolidated Statements of Income. Prior year comparatives have also been retrospectively reclassified, with $4.4 million previously recorded as a reduction in "Income from equity investments" in Q1, 2011 reclassified to "Income tax expense (recovery)" in the Consolidated Statements of Income.

FIRST QUARTER

Interim Report to Shareholders
For the three months ended March 31, 2012

ENBRIDGE INC.

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars)

- First quarter earnings were $264 million including unrealized non-cash mark-to-market losses
- First quarter adjusted earnings increased 14% to $376 million
- U.S. Gulf Coast access initiative upsized to a $5.2 billion investment
- Acquisition of a 100% interest in the 50-megawatt Silver State North Solar Project development in Nevada
- Issuance of $1.05 billion in preference shares
- Enbridge named one of the Global 100 Most Sustainable Corporations, one of Canada's Greenest Employers and a member of the FTSE4Good Index

CALGARY, ALBERTA, May 9, 2012 – Enbridge Inc. (TSX:ENB) (NYSE:ENB) – "With first quarter adjusted earnings of $376 million, or $0.50 per share, Enbridge begins 2012 firmly on track to achieve our full year adjusted earnings guidance of $1.58 to $1.74 per share," said Patrick D. Daniel, Chief Executive Officer.

First quarter 2012 earnings of $264 million included unrealized non-cash mark-to-market losses, primarily related to the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions. These short-term non-cash fluctuations in reported earnings are a result of Enbridge's hedging program, which over the long-term will support the Company's reliable cash flows and capacity for ongoing dividend growth.

In the first quarter, Enbridge announced it had received sufficient commitments from shippers to upsize its proposed Flanagan South Pipeline Project and, with joint venture partner, Enterprise Products Partners, L.P. (Enterprise) to twin the Seaway Crude Pipeline System, bringing Enbridge's expected investment in its U.S. Gulf Coast initiative to $5.2 billion.

"The commitments secured in the open seasons held in the fourth quarter of last year and the first quarter of 2012 will support additional infrastructure to meet the growing transportation needs of Bakken and western Canadian producers and U.S. Gulf Coast refiners, contributing to North America's energy security," said Mr. Daniel. "The new upsized Flanagan South Pipeline, combined with our existing Spearhead Pipeline system, will offer shippers 775,000 barrels per day of capacity from Flanagan to Cushing, with the Seaway Crude Pipeline System reversal and expansion offering capacity of 850,000 barrels per day from Cushing to the Gulf Coast.

"By leveraging existing infrastructure wherever possible, impacts to landowners, communities and the environment will be minimized," added Mr. Daniel.

In green energy, Enbridge added to its growing portfolio of renewable generation assets with the acquisition of a 100% interest in the Silver State North Solar Project (Silver State) development in Nevada.

"Silver State marks Enbridge's entry into the U.S. solar energy market, which offers significant growth opportunities given the excellent solar resource, supportive regulatory environment and expanding portfolio of solar energy projects," said Mr. Daniel. "The project complements Enbridge's growing portfolio of renewable and alternative energy technologies that now includes interests in eight wind farms, four solar projects, a hybrid fuel cell, geothermal and four waste heat recovery facilities. Together, Enbridge has interests in a renewable energy portfolio of almost 1,000 megawatts."

During the quarter, Enbridge continued to be active in capital markets. Noted Mr. Daniel, “Over the past eight months Enbridge has issued $2 billion in preference shares, bolstering our balance sheet as we embark upon the largest slate of growth projects we’ve ever had before us.”

In January, Enbridge was recognized as one of the Corporate Knights Global 100 Most Sustainable Corporations, and in March, FTSE Group reaffirmed Enbridge's membership in the FTSE4Good Index series which identifies companies that meet globally recognized corporate responsibility standards. In April, Enbridge was named one of Canada's Greenest Employers.

“It is gratifying to be recognized for the sustainability of our business model, our commitment to delivering on our social responsibilities, and our continuing efforts to minimize the environmental impact of our activities,” said Mr. Daniel. “Enbridge’s more than 7,000 employees work tirelessly to achieve our vision of being the leading energy delivery company in North America. I thank all of them for their outstanding work and continuing commitment to our corporate values and to Corporate Social Responsibility.”

“Enbridge continues to deliver strong financial performance across our liquids pipelines, gas pipelines and processing, gas distribution and green energy businesses,” concluded Mr. Daniel. “We have had exceptional success in securing new projects across all of our business units, we are well positioned to fund our growth and, with a strong start to the year, we expect to continue to deliver superior returns to our investors.”

FIRST QUARTER 2012 OVERVIEW

For more information on Enbridge's growth projects and operating results, please see the Management's Discussion and Analysis (MD&A) which is filed on SEDAR and EDGAR and also available on the Company’s website at www.enbridge.com/InvestorRelations.aspx.

- The decrease in earnings from $364 million for the first quarter of 2011 to $264 million for the first quarter of 2012 was primarily due to the recognition of net unrealized fair value losses of $110 million (2011 - nil) from the revaluation of financial derivatives related to the Company’s risk management activities. Contributing to the overall decrease in earnings were lower earnings from Enbridge Gas Distribution (EGD) due to warmer weather. Partially offsetting these quarter-over-quarter declines were increased earnings from Liquids Pipelines as a result of favourable operating performance under the Competitive Toll Settlement.

- Enbridge’s first quarter adjusted earnings increased 14% to $376 million as a result of increased contributions from Canadian Mainline, which benefited from strong volumes, continued positive performance at EGD reflecting favourable operating performance, and an increase in earnings from Enbridge Energy Partners, L.P. due to stronger results from the liquids and natural gas businesses, as well as higher incentive income. Corporate earnings also contributed to increased first quarter adjusted earnings due to the Company’s increased investment in Noverco Inc. (Noverco) and lower residual financing costs.

- On May 7, 2012, Enbridge announced Silver State began commercial operation. A 100% interest in the 50-megawatt Silver State development in Clark County, Nevada was acquired in March 2012 at an estimated cost of $0.2 billion. Located 65 kilometers (40 miles) south of Las Vegas, Nevada, Silver State was constructed under a fixed-price engineering, procurement and construction agreement with First Solar. First Solar will provide operations and maintenance services under a long-term contract. NV Energy will purchase the energy output under a 25-year power purchase agreement.

- On April 19, 2012, Enbridge announced the closing of the issue of eight million cumulative redeemable preference shares, series J at a price of US$25 per share for aggregate gross proceeds of US$200 million.

- On April 16, 2012, the Government of New Brunswick enacted a final rates and tariffs regulation which set limits on gas distribution rates within the province. Enbridge had advised on March 12, 2012, when the regulation was still in draft form, that it faced a potential write down of a significant portion of the value of its investment in Enbridge Gas New Brunswick (EGNB), the New Brunswick gas distribution utility. With the finalization of the regulation, Enbridge has confirmed a write down of $262 million. The impact of this charge was recognized as a subsequent event in the Company’s 2011 United States generally accepted accounting principles (U.S. GAAP) consolidated financial statements, voluntarily filed on May 2, 2012.

  On April 26, 2012, the Company, Enbridge Energy Distribution Inc. (EEDI) and EGNB, commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen’s Bench, claiming damages in the amount of $650 million as a result of the continuing breaches by the Province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen’s Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. There is no assurance these actions will be successful or will result in any recovery.

- On March 29, 2012, Enbridge closed its offering of cumulative redeemable preference shares, series H. Due to strong investor demand, the size of the offering was increased to 14 million shares, for aggregate gross proceeds of $350 million.

- Enbridge announced on March 26, 2012, its intent to upsize the capacity of its U.S. Gulf Coast Access projects. The Flanagan South Pipeline from Flanagan, Illinois to Cushing, Oklahoma will be upsized to a 36-inch diameter line with an initial annual capacity of 585,000 barrels per day (bpd). Enbridge, with joint venture partner Enterprise will construct an 805-kilometre (500-mile), 30-inch diameter twin (a parallel line) along the route of their jointly owned Seaway Pipeline, adding 450,000 bpd of capacity to the existing system. The partners will also proceed with construction of an extension from Houston to Port Arthur/Beaumont, adding 560,000 bpd of capacity to that system. The total estimated cost of the Flanagan South Pipeline project, as a result of the larger capacity and pipeline size, has increased from the original US$1.9 billion to US$2.8 billion. In addition, the Enbridge share of the cost of the Seaway Pipeline twin line and extension is expected to be approximately US$1.0 billion.

  The increased Flanagan South Pipeline and Seaway Pipeline capacity is required to accommodate additional commitments for Gulf Coast service, originating from both Flanagan and Cushing, received through recently completed second open seasons. Both the Flanagan South Pipeline and Seaway twin pipeline are expected to be in service by mid-2014.

  Enterprise and Enbridge are nearing completion of the first phase of the reversal of the Seaway Pipeline, which will provide 150,000 bpd of southbound takeaway capacity from Cushing to the Gulf Coast, anticipated to be in service in May 2012. Following pump station additions and modifications, which are expected to be completed by the first quarter 2013, capacity would increase to 400,000 bpd depending upon the mix of light and heavy grades of crude oil.

- On March 22, 2012, Noverco sold 22.5 million Enbridge common shares through a secondary offering. Enbridge’s share of the proceeds of approximately $317 million, expected to be received as a dividend from Noverco in the second quarter of 2012, will be used to pay a portion of the Company’s quarterly dividend on June 1, 2012.

- On February 27, 2012, the Board of Directors of Enbridge announced that Patrick D. Daniel, President and Chief Executive Officer (CEO), will retire at or before the end of 2012. The Board also announced the appointment of Al Monaco, previously President, Gas Pipelines, Green Energy and International, to Enbridge's Board of Directors and to the position of President, effective February 27, 2012. Mr. Daniel will continue as CEO and a member of the Board until his retirement.

- On February 23, 2012, Enbridge welcomed the publication of Transport Canada's TERMPOL Review Process Report of the proposed Northern Gateway Project's proposed marine operations. Transport Canada has filed the results of the study with the federal Joint Review Panel (JRP) tasked with assessing the project. The study reviewed the marine operations associated with the Northern Gateway terminal and associated tanker traffic in Canadian waters. The review concluded that: "While there will always be residual risk in any project, after reviewing the proponent's studies and taking into account the proponent's commitments, no regulatory concerns have been identified for the vessels, vessel operations, the proposed routes, navigability, other waterway users and the marine terminal operations associated with vessels supporting the Northern Gateway Project." The TERMPOL report was prepared and approved by Canadian government authorities including Transport Canada; Environment Canada; Fisheries and Oceans Canada; Canadian Coast Guard; and Pacific Pilotage Authority Canada. Further review of the Northern Gateway application by the JRP, as well as other agencies, is ongoing.

- On January 18, 2012, Enbridge closed the offering of cumulative redeemable preference shares, series F. Due to strong investor demand, the size of the offering was increased to 20 million shares, resulting in aggregate gross proceeds of $500 million.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE MONTHS ENDED MARCH 31, 2012

This Management's Discussion and Analysis (MD&A) dated May 8, 2012 should be read in conjunction with the unaudited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three months ended March 31, 2012, prepared in accordance with United States generally accepted accounting principles (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements, which were prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook (Part V), and MD&A contained in the Company's Annual Report for the year ended December 31, 2011, as well as the consolidated financial statements for the year ended December 31, 2011 that were prepared in accordance with U.S. GAAP and filed on a voluntary basis to facilitate understanding of the Company's transition to U.S. GAAP. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

CONSOLIDATED EARNINGS

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**191**	136
Gas Distribution	**78**	102
Gas Pipelines, Processing and Energy Services	**(111)**	26
Sponsored Investments	**66**	55
Corporate	**40**	45
Earnings attributable to common shareholders	**264**	364
Earnings per common share[1]	**0.35**	0.49
Diluted earnings per common share[1]	**0.34**	0.48

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

Earnings attributable to common shareholders were $264 million for the three months ended March 31, 2012, or $0.35 per common share, compared with $364 million, or $0.49 per common share, for the three months ended March 31, 2011. The decrease in earnings was primarily due to the recognition of unrealized fair value losses within Energy Services related to the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions and revaluation of inventory. Contributing to the overall decrease in earnings were lower earnings from Enbridge Gas Distribution (EGD) due to warmer weather. Partially offsetting these quarter-over-quarter declines were increased earnings from Liquids Pipelines as a result of favourable operating performance under the Competitive Toll Settlement (CTS) and recognition of unrealized fair value gains in Canadian Mainline related to the risk management of exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices. Also, income taxes were lower for the three months ended March 31, 2012 compared with the three months ended March 31, 2011 primarily due to a decrease in the effective income tax rate as a result of losses arising on certain risk management activities in the Company's United States operations.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'' and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings or adjusted earnings; expected earnings or adjusted earnings per share; expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids (NGL); prices of crude oil, natural gas and NGL; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas and NGL, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings or adjusted earnings and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, commodity prices and supply and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the financial results sections for the affected business segments. Management believes that the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, assess performance of the Company and set the Company's dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

ADJUSTED EARNINGS

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**158**	136
Gas Distribution	**102**	91
Gas Pipelines, Processing and Energy Services	**36**	39
Sponsored Investments	**67**	53
Corporate	**13**	11
Adjusted earnings	**376**	330
Adjusted earnings per common share[1]	**0.50**	0.44

1 Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.

Adjusted earnings were $376 million, or $0.50 per common share, for the three months ended March 31, 2012 compared with $330 million, or $0.44 per common share, for the three months ended March 31, 2011. The increase resulted from positive contributions from almost all of the Company's business segments, including:

- Within Liquids Pipelines, increased contributions from Canadian Mainline which benefited from strong volumes, as well as from Feeder Pipelines and Other.
- Continued positive performance at EGD reflecting favourable operating performance under the current Incentive Regulation term as well as an increased contribution from Enbridge Gas New Brunswick (EGNB) due to seasonal winter demand. Under the new regulations to which EGNB is subject, rate regulated accounting no longer applies and EGNB earnings will reflect variability from seasonal demand.
- Within Sponsored Investments, increased contributions from Enbridge Energy Partners, L.P. (EEP), due to higher volumes and tolls, and increased contributions from Enbridge Income Fund (the Fund) due to the acquisition and strong operating performance of certain renewable energy assets.
- In Corporate, higher preference share dividends were more than offset by lower residual financing costs and stronger results from Noverco Inc. (Noverco), resulting in an overall increase in adjusted earnings.

RECENT DEVELOPMENTS

CHIEF EXECUTIVE OFFICER SUCCESSION PLANS

On February 27, 2012, the Board of Directors announced that Patrick D. Daniel, President and Chief Executive Officer (CEO), will retire at or before the end of 2012. The Board also announced the appointment of Al Monaco, previously President, Gas Pipelines, Green Energy and International, to Enbridge's Board of Directors and to the position of President, effective February 27, 2012. Mr. Daniel will continue as CEO and a member of the Board until his retirement. With Mr. Monaco's appointment as President, Leon Zupan was appointed President, Gas Pipelines.

LIQUIDS PIPELINES

Southern Lights Pipeline

Both the Canadian and United States uncommitted rates on Southern Lights Pipeline for 2010, 2011 and 2012 were challenged by Exxon Mobil and Imperial Oil. The Canadian Southern Lights toll hearing was held before National Energy Board (NEB) panel members in November 2011. On February 9, 2012, the NEB issued its decision rejecting the challenge from uncommitted shippers stating that tolls in place are just and reasonable and more recently approved the 2010, 2011 and 2012 interim tolls as final. A Federal Energy Regulatory Commission (FERC) hearing was held in January 2012. Briefs were filed on February 27 and March 28, 2012 and an initial decision is expected on or before June 5, 2012. No material financial impact to the Company is anticipated to result from the FERC proceeding.

Norman Wells Pipeline Crude Oil Release
The Norman Wells Pipeline is a 12-inch, 39,400 barrels per day (bpd) line transporting sweet crude oil that stretches 869 kilometres (540 miles) from Norman Wells, Northwest Territories (NWT) to Zama, Alberta. On May 9, 2011, Enbridge reported a crude oil release from the Norman Wells Pipeline approximately 50 kilometres (31 miles) south of the community of Wrigley, NWT. On May 20, 2011, Enbridge returned the Norman Wells line to service after completing necessary repairs. Excavation of all contaminated soils from the spill site was completed in late November 2011. Based on the volume of contaminated materials removed from the site, the current estimate of volume released is approximately 1,600 barrels. Site reclamation work is anticipated to be completed in the summer of 2012. Monitoring of surface water and groundwater at the site will continue until remediation and reclamation goals have been achieved in accordance with plans filed with the regulator. Currently, Management does not believe this incident will have a material impact on the Company's consolidated financial position or results of operations.

GAS DISTRIBUTION
Enbridge Gas New Brunswick – Regulatory Matters
On December 9, 2011 the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permitted the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. However, significant details of the rate setting process were left to be established in the new regulations and, as such, the effect of such legislation was not determinable at that time.

A final rates and tariffs regulation was subsequently enacted by the Government of New Brunswick on April 16, 2012. Based on the amendments to the rate setting methodology outlined therein EGNB will no longer meet the criteria for the continuation of rate regulated accounting. As a result, the Company must eliminate from its consolidated statements of financial position a deferred regulatory asset of $180 million and a regulatory asset with respect to capitalized operating costs of $103 million, net of an income tax recovery of $21 million.

As the final rates and tariffs regulation published on April 16, 2012 provided further evidence of a condition that existed on December 31, 2011, recognition of the charge totaling $262 million, after tax, was reflected as a subsequent event in the Company's U.S. GAAP consolidated financial statements for the year ended December 31, 2011, which were voluntarily filed with the Canadian Securities Administrators and the United States Securities and Exchange Commission (SEC) on May 2, 2012. The charge reflects Management's best estimate based on facts available at this time and may be subject to further revision based on future actions or interpretations of the regulator, the Government of New Brunswick or other factors.

On April 26, 2012, the Company, Enbridge Energy Distribution Inc. (EEDI) and EGNB, commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen's Bench, claiming damages in the amount of $650 million as a result of the continuing breaches by the Province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen's Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. There is no assurance these actions will be successful or will result in any recovery.

SPONSORED INVESTMENTS
EEP Lakehead System Line 6A and 6B Crude Oil Releases
Enbridge holds an approximate 23% combined direct and indirect ownership interest in EEP. Under U.S. GAAP, Enbridge consolidates EEP and its earnings, net of noncontrolling interests, are reflected within the Sponsored Investments segment.

Line 6B Crude Oil Release

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with extended submerged oil recovery operations, including reassessment, remediation and restoration of the area and air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All of the initiatives EEP will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

The total cost estimate for this incident remains at approximately US$765 million ($129 million after-tax attributable to Enbridge) at March 31, 2012 based on a review of costs and commitments incurred coupled with the evaluation of additional information regarding requirements for environmental restoration and remediation. Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at March 31, 2012. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

In connection with this crude oil release, the cost estimate remains at US$48 million ($7 million after-tax attributable to Enbridge), before any third party or insurance recoveries and excluding fines and penalties.

EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge’s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP’s remediation spending through March 31, 2012, Enbridge and its affiliates have exceeded the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

In the first quarter of 2012, EEP received insurance payments of US$50 million ($7 million after-tax attributable to Enbridge) for insurance receivable claims previously recognized as a reduction to environmental costs in 2011. At March 31, 2012, EEP had collected total insurance recoveries of US$335 million ($50 million after-tax attributable to Enbridge) for the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to EEP’s insurance policies during the period that EEP deems realization of the claim for recovery to be probable. In the first quarter of 2011, EEP recognized insurance recoveries of US$35 million ($5 million after-tax attributable to Enbridge) for claims that it filed while no such recoveries were recognized during the first quarter of 2012.

Enbridge's current comprehensive insurance program, expiring April 30, 2012, has a current liability aggregate limit of US$575 million, including pollution liability. Enbridge will renew its liability insurance and expects to increase the aggregate limit of coverage effective May 1, 2012 through April 30, 2013.

Legal and Regulatory Proceedings
A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, these actions are not expected to be material. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at March 31, 2012. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

Enbridge Income Fund
Saskatchewan System Shipper Complaint
On December 17, 2010, the Saskatchewan System filed amended Westspur tariffs with the NEB with an effective date of February 1, 2011. In January 2011, a shipper on the Westspur System requested the NEB make the tolls "interim" effective February 1, 2011 pending discussions between the shipper and the Saskatchewan System on information requests put forward by the shipper. Subsequently, the shipper filed a complaint with the NEB on the basis the information provided by the Saskatchewan System was not adequate to allow for an assessment to be made of the reasonableness of the tolls. Six parties have filed letters with the NEB supporting the shipper's complaint. The NEB directed additional discussion among the parties and, as of May 7, 2012, the Fund continues to discuss the reasonableness of its Westspur tolls with shippers.

CORPORATE
Noverco
Noverco holds, directly and indirectly, an investment in Enbridge common shares. Noverco had advised Enbridge that the substantial increase in the value of these shares over the last decade resulted in a significant shift in the balance of Noverco's asset mix. The Board of Directors of Noverco authorized the Caisse de Depot et Placement de Quebec, as manager of Noverco, to sell a portion of its Enbridge common share holding and rebalance Noverco's asset mix. On March 22, 2012 Noverco sold 22.5 million Enbridge common shares through a secondary offering. Enbridge's share of the proceeds of approximately $317 million, expected to be received as a dividend from Noverco in the second quarter of 2012, will be used to pay a portion of the Company's quarterly dividend on June 1, 2012. *See Liquidity and Capital Resources – Financing Activities.*

Preference Share Issuances
Series F
On January 18, 2012, the Company issued 20 million Preference Shares, Series F for gross proceeds of $500 million. The 4.0% Cumulative Redeemable Preference Shares, Series F are entitled to a fixed, cumulative, quarterly preferential dividend of $1 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding preference shares for $25 per share plus all accrued and unpaid dividends on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series F will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series G, subject to certain conditions, on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series G will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate plus 2.51%.

Series H
On March 29, 2012, the Company issued 14 million Preference Shares, Series H for gross proceeds of $350 million. The 4.0% Cumulative Redeemable Preference Shares, Series H are entitled to a fixed, cumulative, quarterly preferential dividend of $1 per share per annum. The Company may, at its option,

redeem all or a portion of the outstanding preference shares for $25 per share plus all accrued and unpaid dividends on September 1, 2018 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series H will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series I, subject to certain conditions, on September 1, 2018 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series I will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate plus 2.12%.

Series J

On April 19, 2012, the Company issued eight million Preference Shares, Series J for gross proceeds of US$200 million. The 4.0% Cumulative Redeemable Preference Shares, Series J are entitled to a fixed, cumulative, quarterly preferential dividend of US$1 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding preference shares for US$25 per share plus all accrued and unpaid dividends on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series J will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series K, subject to certain conditions, on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series K will be entitled to receive quarterly floating rate cumulative dividends at a rate equal the sum of the then 90-day US Government Treasury bill rate plus 3.05%.

GROWTH PROJECTS

The table below summarizes the current status of the Company's commercially secured projects, in each of the Company's business segments.

	Actual/ Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
LIQUIDS PIPELINES				
1. Edmonton Terminal Expansion	$0.3 billion	$0.1 billion	2012	Under construction
2. Woodland Pipeline	$0.3 billion	$0.2 billion	2012	Substantially complete
3. Wood Buffalo Pipeline	$0.4 billion	$0.2 billion	2012	Under construction
4. Seaway Crude Pipeline System (including reversal, expansion and extension)	US$2.4 billion	US$1.2 billion	2012-2014 (in phases)	Under construction
5. Waupisoo Pipeline Capacity Expansion	$0.4 billion	$0.2 billion	2012-2013 (in phases)	Under construction
6. Norealis Pipeline	$0.5 billion	$0.1 billion	2013	Under construction
7. Athabasca Pipeline Capacity Expansion	$0.4 billion	$0.1 billion	2013-2014 (in phases)	Pre-construction
8. Flanagan South Pipeline Project	US$2.8 billion	No significant expenditures to date	2014	Pre-construction
9. Athabasca Pipeline Twinning	$1.2 billion	No significant expenditures to date	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES				
10. Silver State North Solar Project	US$0.2 billion	US$0.2 billion	2012	Complete
11. Lac Alfred Wind Project	$0.3 billion	$0.1 billion	2012-2013 (in phases)	Under construction
12. Cabin Gas Plant	$1.1 billion	$0.5 billion	2012-2014 (in phases)	Under construction

	Actual/ Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
13. Tioga Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
14. Venice Condensate Stabilization Facility	US$0.2 billion	No significant expenditures to date	2013	Pre-construction
15. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.1 billion	2014	Pre-construction
16. Big Foot Oil Pipeline	US$0.2 billion	No significant expenditures to date	2014	Pre-construction
SPONSORED INVESTMENTS				
17. EEP - Bakken Expansion Program	US$0.4 billion	US$0.1 billion	2013	Under construction
18. The Fund - Bakken Expansion Program	$0.2 billion	No significant expenditures to date	2013	Pre-construction
19. EEP - Cushing Terminal Storage Expansion Project	US$0.1 billion	US$0.1 billion	2012	Under construction
20. EEP - South Haynesville Shale Expansion	US$0.3 billion	US$0.2 billion	2012+	Under construction
21. EEP - Line 5 Expansion	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
22. EEP - Ajax Cryogenic Processing Plant	US$0.2 billion	No significant expenditures to date	2013	Under construction
23. EEP - Bakken Access Program	US$0.1 billion	No significant expenditures to date	2013	Under construction
24. EEP - Berthold Rail Project	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
25. EEP - Texas Express Pipeline	US$0.4 billion	No significant expenditures to date	2013	Under construction
26. EEP - Line Replacement Program	US$0.3 billion	No significant expenditures to date	2013	Pre-construction
CORPORATE				
27. Montana-Alberta Tie-Line	US$0.4 billion	US$0.3 billion	2012-2013 (in stages)	Under construction

1 *These amounts are estimates only and subject to upward or downward adjustment based on various factors. As appropriate, the amounts reflect Enbridge's share of joint venture projects.*

2 *Expenditures to date reflect total cumulative expenditures incurred from inception of project up to March 31, 2012.*

LIQUIDS PIPELINES

Edmonton Terminal Expansion

The Edmonton Terminal Expansion Project involves expanding the tankage of the mainline terminal at Edmonton, Alberta by one million barrels at an estimated cost of $0.3 billion, with expenditures to date of approximately $0.1 billion. The expansion is required to accommodate growing oil sands production receipts both from Enbridge's Waupisoo Pipeline and other non-Enbridge pipelines. The expansion will be conducted over two phases and will consist of the construction of four tanks and the installation of three booster pumps and related infrastructure. Regulatory approval was received in the first quarter of 2011 and the expansion is expected to be completed by December 2012.

Woodland Pipeline

Enbridge entered into a joint venture agreement with Imperial Oil Resources Ventures Limited and ExxonMobil Canada Properties to provide for the transportation of blended bitumen from the Kearl oil sands mine to crude oil hubs in the Edmonton, Alberta area. The project will be phased with the mine expansion, with the first phase involving construction of a new 140-kilometre (87-mile) 36-inch diameter pipeline from the mine to the Cheecham Terminal, and service on Enbridge's existing Waupisoo Pipeline from Cheecham to the Edmonton area. The new Woodland Pipeline may be extended from Cheecham to Edmonton as part of future industry expansions. Regulatory approval for the Phase I facilities was received in June 2010 and construction is substantially complete. The total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion, of which Enbridge's share is approximately $0.3 billion. Enbridge's share of total project expenditures to date is approximately $0.2 billion. Enbridge expects the pipeline will come into service in late 2012.

Wood Buffalo Pipeline

Enbridge entered into an agreement with Suncor Energy Inc. (Suncor) to construct a new, 95-kilometre (59-mile) 30-inch diameter crude oil pipeline, connecting the Athabasca Terminal adjacent to Suncor's oil sands plant to the Cheecham Terminal, which is the origin point of Enbridge's Waupisoo Pipeline. The Waupisoo Pipeline already delivers crude oil from several oil sands projects to the Edmonton mainline hub. The new Wood Buffalo Pipeline will parallel the existing Athabasca Pipeline between the Athabasca and Cheecham Terminals. The estimated capital cost is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion. Construction of the pipeline was substantially completed in the first quarter of 2012, with in service expected by late 2012 upon completion of the related facilities.

Seaway Crude Pipeline System

Acquisition of Interest

In 2011, Enbridge acquired a 50% interest in the Seaway Pipeline system at a cost of approximately US$1.2 billion. The 1,078-kilometre (670-mile) Seaway Pipeline includes the 805-kilometre (500-mile), 30-inch diameter long-haul system from Freeport, Texas to Cushing, Oklahoma, as well as the Texas City Terminal and Distribution System which serves refineries in the Houston and Texas City areas. Seaway Pipeline also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and four import docks at two locations. The other 50% interest in the Seaway Pipeline system is owned by Enterprise Products Partners L.P. (Enterprise).

Reversal

In December 2011, Enbridge and Enterprise announced plans to reverse the flow direction of the 805-kilometre (500-mile) 30-inch diameter Seaway Pipeline, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the U.S. Gulf Coast. Included in the project scope is a 105-kilometre (65-mile), 36-inch new-build lateral from the Seaway Jones Creek facility southwest of Houston, Texas into Enterprise's ECHO crude oil terminal (ECHO Terminal) southeast of Houston. Enbridge's expected cost for the reversal is approximately US$0.2 billion. The initial 150,000 bpd of capacity on the reversed system is expected to be available by the second quarter of 2012. Following pump station additions and modifications, which are expected to be completed by the first quarter of 2013, capacity would increase to 400,000 bpd depending upon the mix of light and heavy grades of crude oil.

Expansion and Extension

In March 2012, Enbridge and Enterprise, based on additional capacity commitments from shippers, announced plans to proceed with an expansion of the Seaway Pipeline through construction of a second line that will more than double its capacity to 850,000 bpd by mid-2014. This 30-inch diameter pipeline will twin the existing Seaway system following the same routing.

In addition, a proposed 137-kilometre (85-mile) pipeline is expected to be built from the ECHO Terminal to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region's heavy oil refining capabilities. This lateral will offer incremental capacity of 560,000 bpd and is expected to be available in early 2014. Enbridge's investment to twin the pipeline and for the Port Arthur lateral is expected to be approximately US$1.0 billion.

Waupisoo Pipeline Capacity Expansion

The Waupisoo Pipeline Capacity Expansion, which received regulatory approval in November 2010, is expected to provide 65,000 bpd of additional capacity in the second half of 2012 and an estimated 190,000 bpd of additional capacity in the second half of 2013 when the expansion is fully in service. The estimated cost of the project is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion.

Norealis Pipeline
In order to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project, the Company will construct a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the proposed Norealis Terminal to the Cheecham Terminal, and additional tankage at Cheecham. The estimated cost of the project is approximately $0.5 billion, with expenditures to date of approximately $0.1 billion. With regulatory approval received in the second quarter of 2011, the project is expected to be in service in late 2013.

Athabasca Pipeline Capacity Expansion
The Company will undertake an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including incremental production from the Christina Lake Oilsands Project operated by Cenovus. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on the type of crude oil. The estimated cost of full expansion is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion and an expected in service date of 2013 for an initial 430,000 bpd of capacity. The balance of additional capacity is expected to be available by early 2014. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta.

Flanagan South Pipeline Project
The Flanagan South Pipeline will transport crude oil from the Company's terminal at Flanagan, Illinois to Cushing, Oklahoma. Based on the results of a second open season held in the first quarter of 2012, the Flanagan South Pipeline will be upsized to a 36-inch diameter line with an initial annual capacity of 585,000 bpd, increasing the total expected cost of the project from the original US$1.9 billion to US$2.8 billion. Subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014. Both the Seaway and Flanagan South pipelines are included in the Company's Gulf Coast Access initiative to offer crude oil transportation from its terminal at Flanagan to the United States Gulf Coast.

Athabasca Pipeline Twinning
This project includes twinning the southern section of the Company's Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to accommodate the need for additional capacity to serve the Kirby Lake area expected oil sands growth. The expansion project, with an estimated cost of approximately $1.2 billion, will include 345 kilometres (210 miles) of 36-inch pipeline within the existing Athabasca Pipeline right-of-way. The initial annual capacity of the twin pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. The line is expected to enter service in 2015.

Northern Gateway Project
The Northern Gateway Project involves constructing a twin 1,177-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine and tank terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is proposed to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to import condensate and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

Northern Gateway submitted an application to the NEB in May 2010. The Joint Review Panel (JRP) established to review the proposed project, pursuant to the NEB Act and the Canadian Environmental Assessment Act, has a broad mandate to assess the potential environmental effects of the project and to determine if it is in the public interest. The JRP conducted sessions with the public, including Aboriginal groups, to receive comments on the draft List of Issues, additional information which Northern Gateway should be required to file and locations for the oral hearings. The JRP decided to obtain these comments prior to issuing a Hearing Order or initiating further procedural steps in the joint review process. In January 2011, the JRP issued a decision requiring Northern Gateway to provide certain additional information on the design and risk assessment of the pipelines before it would issue a Hearing Order. This information, together with other updates regarding the project, was provided to the JRP in March 2011 and the JRP issued a Hearing Order in May 2011 outlining the procedures to be followed.

In June 2011, Northern Gateway filed additional materials with the JRP including, but not limited to, details of its extensive program of consultation with over 40 Aboriginal communities between December

2009 and March 2011. The update summarized the information provided to Aboriginal groups, the engagement activities that have occurred, the interests and concerns that have been expressed to Northern Gateway, commitments and mitigation measures in response to those concerns and an update on the status of Aboriginal Traditional Knowledge study programs. In August 2011, Northern Gateway filed commercial agreements with the NEB which provide for committed long-term service and capacity on both the proposed crude oil export and condensate import pipelines. Capacity has also been reserved for use by uncommitted shippers.

In the fall of 2011, Northern Gateway responded to written questions by interveners and government participants.

In a Procedural Direction issued in December 2011, the JRP indicated community hearings would be scheduled so the Panel will hear all oral evidence from registered interveners first, followed by oral statements from registered participants. Community hearings for oral evidence took place between January and April 2012. After the Panel has heard all oral evidence, it will then hear oral statements in various communities. A written record of what is said each day in the community hearings is available on the Panel's website. The Panel expects to hold final hearings in September and October 2012 where Northern Gateway, interveners, government participants and the JRP will question those who have presented oral or written evidence. Final Argument is proposed for April 2013. Based on this projected schedule, the JRP would anticipate releasing the Environmental Assessment in the fall of 2013 and its final decision on this project near the end of 2013. Subject to continued commercial support, regulatory and other approvals, and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company currently estimates that Northern Gateway could be in service by 2017 at the earliest, at an estimated cost of $5.5 billion. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.2 billion, including $0.1 billion in funding secured from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project. Given the many uncertainties surrounding the Northern Gateway Project, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

On February 23, 2012, Transport Canada's published its TERMPOL Review Process Report of the proposed Northern Gateway Project's proposed marine operations. Transport Canada has filed the results of the study with the federal JRP tasked with assessing the project. The study reviewed the marine operations associated with the Northern Gateway terminal and associated tanker traffic in Canadian waters. The review concluded that: "While there will always be residual risk in any project, after reviewing the proponent's studies and taking into account the proponent's commitments, no regulatory concerns have been identified for the vessels, vessel operations, the proposed routes, navigability, other waterway users and the marine terminal operations associated with vessels supporting the Northern Gateway Project." The TERMPOL report was prepared and approved by Canadian government authorities including Transport Canada; Environment Canada; Fisheries and Oceans Canada; Canadian Coast Guard; and Pacific Pilotage Authority Canada. Further review of the Northern Gateway application by the JRP, as well as other agencies, is ongoing.

The JRP posts public filings related to Northern Gateway on its website at http://gatewaypanel.review-examen.gc.ca/clf-nsi/hm-eng.html and Enbridge also maintains a Northern Gateway Project website in addition to information available on www.enbridge.com. The full regulatory application submitted to the NEB and the 2010 Enbridge Northern Gateway Community Social Responsibility Report are available on www.northerngateway.ca. None of the information contained on, or connected to, the JRP website, the Northern Gateway Project website or Enbridge's website is incorporated in or otherwise part of this MD&A.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Silver State North Solar Project

In March 2012, Enbridge acquired a 100% interest in the development of the 50-megawatt (MW) Silver State North Solar Project, located 65 kilometres (40 miles) south of Las Vegas, Nevada. The project, which began commercial operation in May 2012, was constructed under a fixed-price engineering, procurement and construction agreement with First Solar. First Solar will provide operations and maintenance services under a long-term contract. NV Energy will purchase the energy output under a 25-year power purchase agreement (PPA). The Company's total investment in the project is expected to be approximately US$0.2 billion.

Lac Alfred Wind Project
Enbridge secured a 50% interest in the development of the 300-MW Lac Alfred Wind Project (Lac Alfred), located 400 kilometres (250 miles) northeast of Quebec City in Quebec's Bas-Saint-Laurent region. The project is being constructed under a fixed price, turnkey, engineering, procurement and construction agreement and will take place in two phases: Phase 1 is expected to be completed in December 2012; while Phase 2 is expected to be completed in December 2013. Hydro-Quebec will purchase the power under a 20-year PPA and will construct the 30-kilometre transmission line to connect Lac Alfred to the grid under an interconnection agreement. The Company's total investment in the project is expected to be approximately $0.3 billion.

Cabin Gas Plant
In December 2011, the Company secured a 71% interest in the development of the Cabin Gas Plant (Cabin), located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin. The Company's total investment in phases 1 and 2 of Cabin is expected to be approximately $1.1 billion. Phase 1 of the development is to have 400 million cubic feet per day (mmcf/d) of processing capacity. The plant is currently under construction and is expected to be in-service in late 2012. Phase 2, which is to provide an additional 400 mmcf/d of capacity, has been sanctioned by the producers and has also received regulatory approval. Phase 2 is expected to be ready for service in the third quarter of 2014. Capacity for both phases 1 and 2 has been fully subscribed by Horn River producers. These producers can request the Company to expand Cabin up to an additional four phases, under agreed terms.

Tioga Lateral Pipeline
Alliance Pipeline US plans to develop a natural gas pipeline lateral and associated facilities to connect production from the Hess Tioga field processing plant in the Bakken region of North Dakota to the Alliance mainline near Sherwood, North Dakota. Through its 50% ownership interest in Alliance Pipeline US, Enbridge's expected cost related to the project is approximately US$0.1 billion. Alliance Pipeline US has executed a precedent agreement with Hess Corporation (Hess) as an anchor shipper on the Tioga Lateral Pipeline. Aux Sable Liquids Products (Aux Sable) and Hess have reached a concurrent agreement for the provision of NGL services. The 124-kilometre (77-mile) Tioga Lateral Pipeline will facilitate movement of high-energy, liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of the Alliance mainline system. The pipeline will have an initial design capacity of approximately 106 mmcf/d, which can be expanded based on shipper demand. On January 25, 2012, Alliance Pipeline US filed an application for regulatory approval to construct and operate the Tioga Lateral and, pending approvals, the pipeline is expected to be in service by mid-2013.

Venice Condensate Stabilization Facility
The Company plans for an estimated US$0.2 billion expansion of the Venice Condensate Stabilization Facility (Venice) at its Venice, Louisiana facility within its Offshore business. The expanded condensate processing capacity will be required to accommodate additional natural gas production from the recently sanctioned Olympus offshore oil and gas development. Natural gas production from Olympus will move to Enbridge's onshore facility at Venice via Enbridge's Mississippi Canyon offshore pipeline where it will be processed to separate and stabilize the condensate. The expansion, which is expected to more than double the capacity of the facility to approximately 12,000 barrels of condensate per day, is expected to be in service in late 2013.

Walker Ridge Gas Gathering System
The Company executed definitive agreements 2010 with Chevron USA, Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge will construct, own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the proposed Jack, St. Malo and Big Foot ultra-deepwater developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter

pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 0.1 billion cubic feet per day. WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.1 billion.

Big Foot Oil Pipeline

The Company executed definitive agreements in the 2011 with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc. to construct and operate a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the proposed Big Foot ultra-deepwater development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge's plans to construct the WRGGS. The estimated cost of the Big Foot Oil Pipeline, which will be located about 274 kilometres (170 miles) south of the coast of Louisiana, is approximately US$0.2 billion and it is expected to be in service in 2014.

SPONSORED INVESTMENTS

Bakken Expansion Program

A joint project to further expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba is being undertaken by EEP and the Fund. The Bakken Expansion Program is expected to provide capacity of 145,000 bpd and, together with the North Dakota mainline, is expected to result in a total takeaway capacity of 355,000 bpd for this region. The Bakken Expansion Program involves United States projects undertaken by EEP at a cost of approximately US$0.4 billion and will involve Canadian projects undertaken by the Fund at a cost of approximately $0.2 billion. Regulatory approval has been received and construction commenced in July 2011 on the United States portion of the project, with expenditures to date of approximately US$0.1 billion. In Canada, NEB approval was secured in December 2011. Subject to other approvals in respect of the Canadian portion, the Bakken Expansion Program is expected to be completed in the first quarter of 2013. On February 28, 2012, the Fund and EEP announced a second open season for the Bakken Expansion Program which closed on April 18, 2012. The open season resulted in additional term commitments to support the project.

Enbridge Energy Partners, L.P.

Cushing Terminal Storage Expansion Project

EEP is constructing 13 new storage tanks at its Cushing Terminal with an approximate shell capacity of 4.4 million barrels. The total estimated cost of the expansion is approximately US$0.1 billion. As of April 30, 2012, nine tanks had been completed and placed into service and the last remaining tanks are expected to come into service by December 2012.

South Haynesville Shale Expansion

EEP is expanding its East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville shale, together with a large diameter lateral pipeline from Shelby County to Carthage. The expansion, with an estimated cost of approximately US$0.1 billion, is expected to increase capacity of EEP’s East Texas system by 900 mmcf/d upon completion in 2012.

EEP plans to invest an additional US$0.2 billion to expand its East Texas system, including the construction of gathering and related treating facilities. EEP has signed long-term agreements with four major natural gas producers along the Texas side of the Haynesville shale to provide gathering, treating and transmission services. Completion of the additional expansion is dependent on drilling plans of these producers. In light of weak gas prices and lower levels of producer activity, EEP has now deferred portions of its Haynesville natural gas expansion pending increases in drilling activity.

Line 5 Expansion and Line 9 Reversal

Enbridge and EEP will undertake two projects to provide increased access to refineries in the United States upper mid-west and in Ontario for light crude oil produced in western Canada and the United States. One project involves the expansion of EEP’s Line 5 light crude oil line between Superior, Wisconsin and Sarnia, Ontario by 50,000 bpd, at a cost of approximately US$0.1 billion. Complementing the Line 5 expansion, Enbridge plans on reversing a portion of its Line 9 in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario at a cost of approximately $20 million.

Subject to regulatory and other approvals, the Line 5 expansion is targeted to be in service during the first quarter of 2013, while the Line 9 reversal is targeted to be in service in late 2013.

Ajax Cryogenic Processing Plant

EEP is constructing an additional processing plant and other facilities on its Anadarko System at an approximate cost of US$0.2 billion. The Ajax Plant, with a planned capacity of 150 mmcf/d, is expected to be in service in early 2013. The Ajax Plant, when operational, in addition to the Allison Plant, is expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d.

Bakken Access Program

The Bakken Access Program, a series of projects totaling approximately US$0.1 billion, represents an upstream expansion that will further complement EEP's Bakken expansion. This expansion program will enhance gathering capabilities on the North Dakota System by 100,000 bpd. The program, which involves increasing pipeline capacities, construction of additional storage tanks and the addition of truck access facilities at multiple locations in western North Dakota, is expected to be in service by early 2013.

Berthold Rail Project

EEP is proceeding with the Berthold Rail Project, a US$0.1 billion investment that will provide an interim solution to shipper needs in the Bakken region. The project is expected to expand capacity into the Berthold Terminal by 80,000 bpd and includes the construction of a three-unit train loading facility, crude oil tankage and other terminal facilities adjacent to existing facilities. A regulatory filing is in progress and detailed design is proceeding to enable construction to commence in April 2012 with an expected in-service date by early 2013.

Texas Express Pipeline

The Texas Express Pipeline (TEP) is a joint venture with Enterprise, Anadarko Petroleum Corporation and DCP Midstream LLC to design and construct a new NGL pipeline, as well as two new NGL gathering systems which EEP will build and operate. EEP will invest approximately US$0.4 billion in the TEP, which will originate in Skellytown, Texas and extend approximately 935 kilometres (580 miles) to NGL fractionation and storage facilities in Mont Belvieu, Texas. TEP is expected to have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. Approximately 250,000 bpd of capacity has been subscribed on the pipeline.

One of the new NGL gathering systems will connect TEP to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma, while the second will connect TEP to central Texas Barnett Shale processing plants. Subject to regulatory approvals and finalization of commercial terms, the pipeline and portions of the gathering systems are expected to begin service in mid-2013.

Line Replacement Program

This program includes the replacement of 120 kilometres (75 miles) of non-contiguous sections of Line 6B of EEP's Lakehead System. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through EEP's tariff surcharge that is part of the system-wide rates of the Lakehead System. EEP subsequently revised the scope of this project to increase the cost by approximately US$30 million, which will bring the total capital for this replacement program to an estimated cost of US$316 million. The US$30 million of additional costs do not currently have recovery under the tariff surcharge.

CORPORATE

Montana-Alberta Tie-Line (MATL)

MATL is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of the growing supply of electric power in Montana and the buoyant power demand in Alberta. The total expected cost for both the first 300-MW phase of MATL and the expansion for an additional 250-MW to 300-MW has been increased to approximately US$0.4 billion, of which approximately half will be funded through a 30-year loan from the Western Area Power Administration of the United States Department of Energy. Expenditures to date are approximately US$0.3 billion. While the permits required for construction have been obtained, the approval in Canada is currently being updated to reflect a number of design modifications which require further consultation with land owners. Subject to these approvals, the system's north-bound capacity, which is fully contracted, is expected to be in-service in the fourth quarter of 2012.

Neal Hot Springs Geothermal Project
The Company has partnered with U.S. Geothermal Inc. to develop the 35-MW Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. The project is anticipated to be completed in the second quarter of 2012 and will deliver electricity to the Idaho Power grid under a 25-year PPA. Construction on the project has commenced and Enbridge will invest up to approximately US$33 million for an expected 41% interest in the project.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Canadian Mainline	**99**	82
Regional Oil Sands System	**27**	27
Southern Lights Pipeline	**17**	19
Spearhead Pipeline	**11**	10
Feeder Pipelines and Other	**4**	(2)
Adjusted earnings	**158**	136
Canadian Mainline - Line 9 tolling adjustment	**6**	-
Canadian Mainline - unrealized derivative fair value gains	**27**	-
Earnings	**191**	136

Canadian Mainline earnings for the first three months of 2012 were governed by the CTS (with the exception of Lines 8 and 9) whereas earnings for the first quarter of 2011 were governed by a series of agreements, the most significant being the Incentive Tolling Settlement applicable to the mainline system and the Terrace and Alberta Clipper agreements. Earnings under the CTS are subject to variability in throughput volume and operating costs. Canadian Mainline volumes during the first quarter of 2012 were higher than expected contributing to an increase in earnings relative to the prior year, partially offset by higher operating and administrative costs, due primarily to the timing of integrity work.

Supplemental information on Canadian Mainline adjusted earnings for the first quarter of 2012 is as follows:

	Three months ended March 31, 2012
(millions of Canadian dollars, unless otherwise noted)	
Revenues	**316**
Expenses	
Operating and administrative	**81**
Power	**29**
Depreciation and amortization	**54**
	164
	152
Other expense	**(3)**
Interest expense	**(31)**
	118
Income taxes	**(19)**
Adjusted earnings	**99**
International Joint Tariff (IJT) Benchmark Toll[1] *(United States dollars per barrel)*	**$3.85**
Lakehead System Local Toll[2] *(United States dollars per barrel)*	**$2.01**
Canadian Mainline IJT Residual Benchmark Toll[3] *(United States dollars per barrel)*	**$1.84**
Effective United States dollar to Canadian dollar exchange rate[4]	**0.96**

1 The benchmark toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil.
2 Per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois.
3 Per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. The Canadian Mainline IJT residual toll for any shipment is the difference between the IJT toll for that shipment and the Lakehead System local toll for that shipment.
4 Inclusive of realized gains or losses on foreign exchange derivative financial instruments.

	Three months ended, March 31,	
	2012	2011
Throughput volume[1] *(thousand barrels per day (kbpd))*	**1,687**	1,602

1 Throughput volume, presented in kbpd, represents mainline deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.

Canadian Mainline revenues included the portion of the system covered by the CTS as well as revenues from Lines 8 and 9 in eastern Canada. Line 8 and Line 9 are currently tolled on a separate basis and comprise a relatively small proportion of total Canadian Mainline revenues. CTS revenues include transportation revenues, the largest component, as well as allowance oil and revenues from receipt and delivery charges. Transportation revenues include revenues for volumes delivered off the Canadian Mainline at Gretna and on to the Lakehead System, to which Canadian Mainline IJT residual benchmark tolls apply, and revenues for volumes delivered to other western Canada delivery points, to which the Canadian Local Toll (CLT) applies. Despite the many factors which affect Canadian Mainline revenues, the primary determinants of those revenues will be throughput volume ex-Gretna, the United States dollar Canadian Mainline IJT residual benchmark toll applicable to those volumes and the effective foreign exchange rate at which resultant revenues are converted into Canadian dollars. The Company may utilize derivative financial instruments to hedge foreign exchange rate risk on United States dollar denominated revenues. The exact relationship between the primary determinants and actual Canadian Mainline revenues will vary somewhat from quarter to quarter but is expected to be relatively stable on average for a year, absent a systematic shift in receipt and delivery point mix or in crude oil type mix.

The largest components of operating and administrative expenses are employee related costs, pipeline integrity, repairs and maintenance, rents and leases and property taxes. Operating and administrative costs are relatively insensitive to throughput volumes. The primary drivers of future increases in operating costs are expected to be normal escalation in wage rates, prices for purchased services and tax rates, addition of new facilities and more extensive integrity and maintenance programs.

Power is the most significant variable operating cost and is subject to variations in operating conditions, including system configuration, pumping patterns and pressure requirements. However, the primary determinants of power cost are the level of power prices in various jurisdictions and throughput volume. The relationship of power consumption to throughput volume is expected to be roughly proportional over a moderate range of volumes. The Company may utilize derivative financial instruments to hedge power prices.

Depreciation and amortization expense will adjust over time as a result of changes in estimated depreciation rates and additions to property, plant and equipment due to new facilities, as well as maintenance and integrity capital expenditures.

Canadian Mainline income taxes reflected current income taxes only. Under the CTS, the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment and, as such, an offsetting regulatory asset related to deferred income taxes is recognized as incurred.

The preceding financial overview includes expectations regarding future events and operating conditions that the Company believes are reasonable based on currently available information; however, such statements are not guarantees of future performance and are subject to change.

Prior to the implementation of the CTS, revenue on the Canadian Mainline was recognized in a manner consistent with the underlying agreements as approved by the regulator, in accordance with rate-regulated accounting. The Company discontinued the application of rate-regulated accounting to its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis commencing July 1, 2011. The regulatory asset balance at the date of discontinuance related to tolling deferrals recognized in prior periods is being recovered through a surcharge to the CLT and IJT. While the CTS is based on previous tolling settlements and cost-of-service principles, earnings are subject to variability associated with throughput volume and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. The regulatory asset of approximately $470 million related to deferred income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of deferred income taxes incurred subsequent to the date of discontinuance and, as such, regulatory assets related to deferred income taxes will continue to be recognized as incurred.

The earnings increase in Feeder Pipelines and Other primarily reflected a higher contribution from Olympic Pipeline resulting from a tariff increase. In 2011, earnings from Toledo Pipeline were negatively impacted by integrity work on Lines 6A and 6B of EEP’s Lakehead System.

Liquids Pipelines earnings were impacted by the following non-recurring or non-operating adjusting items.

- Canadian Mainline earnings for 2012 included a Line 9 tolling adjustment related to services provided in prior periods.
- Canadian Mainline earnings for 2012 reflected unrealized fair value gains on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.

GAS DISTRIBUTION

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Enbridge Gas Distribution (EGD)	**81**	78
Other Gas Distribution and Storage	**21**	13
Adjusted earnings	**102**	91
EGD - colder/(warmer) than normal weather	**(24)**	11
Earnings	**78**	102

The increase in EGD's adjusted earnings was primarily due to customer growth, lower interest expense and lower statutory income tax rates, partially offset by higher system integrity and operating and administrative costs as well as higher depreciation expense. In addition, compared with the prior year, lower per unit volumetric charges with corresponding increases in fixed charges are expected to modify EGD's quarterly earnings profile, but not materially impact full year earnings as earnings are shifted from the colder winter months to the warmer summer months.

Other Gas Distribution and Storage earnings increased primarily due to the discontinuance of rate regulated accounting for EGNB in the first quarter of 2012. This discontinuance will result in earnings being subject to increased variability, including quarterly seasonality, as there will be no further accumulation of the regulatory deferral account. Earnings will increase in the colder winter months when demand for natural gas is high and earnings will decrease in the warmer summer months when demand, and therefore delivered volumes, is low. As a result of recent amendments to the rate setting methodology to which EGNB is subject, on a full year basis, earnings are expected to be approximately 60% lower than the $20 million earned in 2011. *See Recent Developments – Gas Distribution – Enbridge Gas New Brunswick – Regulatory Matters.*

Gas Distribution earnings were impacted by the following non-recurring or non-operating adjusting item.

- EGD earnings are adjusted to reflect the impact of weather.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Enbridge Offshore Pipelines (Offshore)	**3**	2
Alliance Pipeline US	**6**	7
Vector Pipeline	**5**	5
Aux Sable	**12**	11
Energy Services	**4**	9
Other	**6**	5
Adjusted earnings	**36**	39
Aux Sable - unrealized derivative fair value gains/(loss)	**7**	(6)
Energy Services - unrealized derivative fair value loss	**(154)**	(7)
Earnings/(loss)	**(111)**	26

Offshore adjusted earnings for the three months ended March 31, 2012 included a $2 million favourable impact related to the reversal of a shipper reserve pertaining to a rate case from 2011. Overall, Offshore is expected to be in a loss position for the full year as the Company continues to experience weak volumes due to the slower regulatory permitting process and delayed drilling programs by producers in the Gulf of Mexico.

Energy Services employs various marketing strategies to capture basis (location) differentials and tank management revenue when opportunities arise. Energy Services adjusted earnings declined in the first quarter of 2012 due to changing market conditions which gave rise to fewer margin opportunities in liquids marketing.

Gas Pipelines, Processing and Energy Services earnings were impacted by the following non-recurring or non-operating adjusting items.

- Aux Sable earnings for each period reflected unrealized fair value changes on derivative financial instruments related to the Company's forward gas processing risk management position.
- Energy Services earnings for each period reflected unrealized fair value gains and losses related to the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions and the revaluation of inventory.

SPONSORED INVESTMENTS

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Enbridge Energy Partners (EEP)	**36**	31
Enbridge Energy, Limited Partnership - Alberta Clipper US (EELP)	**10**	12
Enbridge Income Fund (the Fund)	**21**	10
Adjusted earnings	**67**	53
EEP - NGL trucking and marketing investigation costs	**(1)**	-
EEP - unrealized derivative fair value loss	**-**	(3)
EEP - leak insurance recoveries	**-**	5
EEP - lawsuit settlement	**-**	1
EEP - impact of unusual weather conditions	**-**	(1)
Earnings	**66**	55

EEP adjusted earnings for the first quarter of 2012 included strong results from the liquids and natural gas businesses, as well as higher incentive income. The increased earnings from the liquids business was primarily due to higher average daily delivery volumes and an increase in transportation rates on all major liquids systems. Earnings from the natural gas business increased as a result of higher natural gas and NGL volumes, in addition to improved processing margins, on the Anadarko System, partially due to new assets placed in service to process the growing natural gas production. These positive impacts were offset by an increase in operating and administrative costs, primarily workforce-related costs, as well as higher interest expense.

Earnings for the Fund for the first quarter of 2012 included earnings from the Ontario Wind, Sarnia Solar and Talbot Wind energy projects (the Renewable Assets) acquired from a wholly-owned subsidiary of Enbridge in October 2011. Prior to October 2011, earnings from the Renewable Assets were presented within the Gas Pipelines, Processing and Energy Services segment. Partially offsetting strong contributions from the Renewable Assets were increased interest costs associated with funding the acquisition as well as higher deferred income taxes.

Sponsored Investment earnings were impacted by the following non-recurring or non-operating adjusting items.

- EEP earnings for 2012 reflected a charge for legal and accounting costs associated with an investigation at a NGL trucking and marketing subsidiary, which was concluded in the first quarter of 2012.
- Earnings from EEP for 2011 included a change in the unrealized fair value on derivative financial instruments in each period.

- Earnings from EEP for 2011 included insurance recoveries associated with the Line 6B crude oil release. *See Recent Developments – Sponsored Investments – EEP Lakehead System Line 6A and 6B Crude Oil Releases.*
- EEP earnings included proceeds related to the settlement of a lawsuit during the first quarter of 2011.
- EEP earnings for 2011 included an unfavourable effect related to decreased volumes due to uncharacteristically cold weather in February 2011 that disrupted normal operations of its natural gas systems.

CORPORATE

	Three months ended March 31	
	2012	2011
(millions of Canadian dollars)		
Noverco	**20**	14
Other Corporate	**(7)**	(3)
Adjusted earnings	**13**	11
Noverco - equity earnings adjustment	**(12)**	-
Other Corporate - unrealized derivative fair value gains	**10**	16
Other Corporate - foreign tax recovery	**29**	-
Other Corporate - unrealized foreign exchange gains on translation of intercompany balances, net	**-**	18
Earnings	**40**	45

Noverco adjusted earnings for the three months ended March 31, 2012 reflected contributions from the Company's increased preferred share investment.

The increase in Other Corporate adjusted loss was primarily due to an increase in preference share dividends following the issuance of 72 million preference shares since the first quarter of 2011, partially offset by lower net Corporate segment financing costs. In April 2012, the Company issued an additional eight million preference shares. *See Recent Developments – Corporate – Preference Share Issuances.*

Corporate costs were impacted by the following non-recurring or non-operating adjusting items.

- Earnings from Noverco for the first quarter of 2012 included an unfavourable equity earnings adjustment related to prior periods.
- Earnings for each period included a change in the unrealized fair value gains on derivative financial instruments related to forward foreign exchange risk management positions.
- Earnings for the first quarter of 2012 were favourably impacted by a recovery of taxes related to a historical foreign investment.
- Earnings for the first quarter of 2011 included net unrealized foreign exchange gains on the translation of foreign-denominated intercompany balances.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. At March 31, 2012, excluding the Southern Lights project financing, the Company had $9,988 million of committed credit facilities of which $3,446 million were drawn or allocated to backstop commercial paper. Inclusive of unrestricted cash and cash equivalents of $875 million, the Company had net available liquidity at March 31, 2012 of $7,417 million. The net available liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently secured capital projects and to provide flexibility for new investment opportunities.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at March 31, 2012.

	Maturity Dates[1]	Total Facilities	Credit Facility Draws[2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**25**	**275**
Gas Distribution	2012-2013	**717**	**290**	**427**
Sponsored Investments	2013-2016	**2,498**	**737**	**1,761**
Corporate[3]	2013-2016	**6,473**	**2,394**	**4,079**
		9,988	**3,446**	**6,542**
Southern Lights project financing[4]	2013-2014	**1,505**	**1,442**	**63**
Total credit facilities		**11,493**	**4,888**	**6,605**

1 *Total facilities include $30 million in demand facilities with no maturity date.*
2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
3 *Includes a revolving credit facility of US$1.3 billion with a maturity date of 2015 that was secured in January 2012.*
4 *Total facilities inclusive of $60 million for debt service reserve letters of credit.*

OPERATING ACTIVITIES

Cash provided by operating activities was $648 million for the three months ended March 31, 2012 compared with $1,163 million for the three months ended March 31, 2011. The Company's growing cash flows from development projects placed into service in recent years, from the favourable operating performance of Canadian Mainline under CTS and from increased contributions from Sponsored Investments, was masked by variations in working capital accounts quarter-over-quarter. Changes in operating assets and liabilities contributed $700 million to the overall net decline in cash provided by operating activities for the first quarter of 2012 compared with the first quarter of 2011. Working capital will fluctuate from time to time due to natural gas inventory and borrowing levels at EGD, which in turn are impacted by weather and commodity prices, as well as activity levels within the Company's Energy Services businesses, among others. Other changes in operating assets and liabilities in the first quarter of 2012 included payment of tax balances remaining from 2011 and receipt of insurance payments for claims made in conjunction with the Line 6B crude oil release, collecting some of the cash outlays incurred in 2011.

There are no material restrictions on the Company's cash with the exception of restricted cash of $7 million related to Southern Lights project financing and cash in trust of $16 million for specific shipper commitments.

INVESTING ACTIVITIES

Cash used in investing activities for the three months ended March 31, 2012 was $928 million compared with $647 million for the three months ended March 31, 2011. Cash used in investing activities included $877 million (2011 - $536 million) of additions to property, plant and equipment, primarily directed to the Company's growth projects which was partially offset by the timing of cash payments of construction payables. The increase in cash used in investing activities was also attributable to greater intangible asset additions, primarily software, and additional funding of various investments and joint ventures, namely the Texas Express and Woodland Pipelines.

FINANCING ACTIVITIES

Cash generated from financing activities was $663 million for the three months ended March 31, 2012 compared with cash used in financing activities of $301 million for the three months ended March 31, 2011. The increase in cash was primarily due to issuances of both preference shares and debenture and term notes of $826 million and $500 million, respectively. The Company accesses capital markets as required to finance currently secured capital projects and to provide flexibility for new growth opportunities. This increase was partially offset by higher net repayments of bank indebtedness and short-term borrowings and commercial paper and credit facility draws. Additionally, cash used in financing activities for the first quarter of 2012 included routine distributions to third party investors in EEP and the Fund of $100 million (2011 - $24 million) and $12 million (2011 - $7 million), respectively.

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended March 31, 2012, dividends declared were $221 million (2011 - $188 million), of which $156 million (2011 - $124 million) were paid in cash and reflected in financing activities. The remaining $65 million (2011 - $64 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three months ended March 31, 2012, 29% (2011 - 34%) of total dividends declared were reinvested.

On April 26, 2012, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2012 to shareholders of record on May 15, 2012.

Common Shares[1]	$0.28250
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F[2]	$0.36990

1 *A portion of this common share dividend, estimated to be $0.2372 per share, will not qualify for the enhanced dividend tax credit in Canada and accordingly, will not be designated as an "eligible dividend". This is because certain of the funds being distributed to shareholders will be sourced from funds received in the form of dividends from Noverco, a private company investee of Enbridge, following the profitable sale of some of Noverco's shares in Enbridge. The remaining portion of the dividend, currently estimated to be $0.0453 per share, will be designated as an "eligible dividend" for Canadian federal income tax purposes. The whole dividend of $0.2825 per share will still be a "qualified dividend" for United States tax purposes.*

2 *This first dividend declared for the Preference Shares, Series F includes accrued dividends from January 18, 2012, the date the shares were issued. The regular quarterly dividend of $0.25 per share will take effect on September 1, 2012. See Recent Developments – Corporate – Preference Share Issuances – Series F.*

Capital Expenditure Commitments

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $3,935 million which are expected to be paid over the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

The Company's earnings, cash flows, and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues denominated in United States dollars. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues denominated in United States dollars.

Interest Rate Risk
The Company’s earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2016 at an average swap rate of 2.32%.

The Company’s earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2016. A total of $7,050 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company uses primarily qualifying derivative instruments to manage interest rate risk.

Commodity Price Risk
The Company’s earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil and NGL. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGL) that impact earnings from its ownership in the Aux Sable natural gas processing plant and the gathering and processing business held by EEP.

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in the Company’s share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted stock units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income
The following table presents the effect of derivative instruments on the Company’s consolidated earnings and consolidated comprehensive income.

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**19**	(19)
Interest rate contracts	**180**	78
Commodity contracts	**(8)**	(56)
Other contracts	**(1)**	1
Net investment hedges		
Foreign exchange contracts	**3**	20
	193	24
Amount of gain/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Cash flow hedges		
Interest rate contracts[1]	**14**	4
Commodity contracts[2]	**2**	(9)
	16	(5)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Cash flow hedges		
Commodity contracts[2]	**(2)**	1
	(2)	1
Amount of unrealized gain/(loss) recognized in earnings		
Non-qualifying derivatives		
Foreign exchange contracts[3]	**15**	22
Interest rate contracts[1]	**(2)**	-
Commodity contracts[2]	**(203)**	(34)
Other contracts[4]	**-**	(2)
Total unrealized derivative fair value loss	**(190)**	(14)

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Transportation and other services revenue, Commodity costs, and Operating and administrative expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenue and Other income in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at March 31, 2012. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK
Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS
The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread, as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

CRITICAL ACCOUNTING ESTIMATES

ASSET RETIREMENT OBLIGATIONS
In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Since then, the NEB has issued several revised “base case assumptions” based on feedback from member companies. Companies have the option to follow the base case assumptions or to submit pipeline specific applications.

On November 29, 2011, as required by NEB, the Company filed its estimates of abandonment costs for its regulated pipeline systems within Enbridge Pipelines Inc. and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc., Enbridge Pipelines (Westspur) Inc., and Vector Pipelines Limited Partnership (Group 2 companies). The NEB is also requiring regulated pipeline companies to file a proposed process for collecting and setting aside the funds for future abandonment costs by November 30, 2012 for Group 1 companies and by March 31, 2013 for Group 2 companies. These costs would be recovered from shippers through tolls in accordance with NEB’s determination that abandonment costs are a legitimate cost of providing services and are recoverable upon NEB approval from users of the system.

Both of the required submissions will require NEB approval and will result in increased transportation tolls and regulatory liabilities. The specific toll impacts are uncertain at this time as they will be the subject of NEB filings in late 2012 and early 2013.

Currently, for certain of the Company’s assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the asset retirement obligation (ARO). In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

CHANGE IN ACCOUNTING POLICIES

United States Generally Accepted Accounting Principles
The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. As an SEC registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

To facilitate users understanding of the transition to U.S. GAAP, the Company restated its 2011 consolidated financial statements, which were originally prepared in accordance with Part V, to U.S. GAAP, including full comparative information and related note disclosure. The 2011 U.S. GAAP financial statement were voluntarily filed with securities regulators in Canada and the United States on May 2, 2012 and are available on SEDAR at www.sedar.com and on the Company's website at www.enbridge.com. None of the information contained on, or connected to, Enbridge's website is incorporated or otherwise part of this MD&A.

Fair Value Measurement
Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board's joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the adoption of this update impacted disclosure only, there was no impact to the Company's earnings or cash flows for the current or prior periods presented.

Statement of Comprehensive Income
Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company's presentation of comprehensive income and did not impact the Company's consolidated financial statements.

Goodwill Impairment
Effective January 1, 2012, the Company adopted ASU 2011-08 which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, it is more likely than not its fair value is less than its carrying amount. Adoption of this standard does not change the current two-step goodwill impairment test.

QUARTERLY FINANCIAL INFORMATION

	2012[1]	2011[1]				2010[2]		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
(millions of Canadian dollars, except per share amounts)								
Revenues	**6,627**	7,237	6,278	6,937	6,529	4,193	3,493	3,518
Earnings attributable to common shareholders	**264**	159	(5)	302	364	326	157	138
Earnings per common share[3]	**0.35**	0.21	(0.01)	0.40	0.49	0.44	0.21	0.19
Diluted earnings per common share[3]	**0.34**	0.21	(0.01)	0.40	0.48	0.43	0.21	0.18
Dividends per common share[3]	**0.2825**	0.2450	0.2450	0.2450	0.2450	0.2125	0.2125	0.2125
EGD - warmer/(colder) than normal weather	**24**	12	-	(2)	(11)	(6)	-	10
Net unrealized derivative fair value and intercompany foreign exchange (gains)/losses	**110**	(251)	251	(17)	(18)	(71)	(45)	87

1 Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.
2 Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.
3 Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.

Several factors impact comparability of the Company's financial results on a quarterly basis, including, but not limited to, seasonality in the Company's gas distribution businesses, fluctuations in market prices such as foreign exchange rates and commodity prices, disposals of investments or assets and the timing of in-service dates of new projects.

EGD and the Company's other gas distribution businesses are subject to seasonal demand. A significant portion of gas distribution customers use natural gas for space heating; therefore, volumes delivered and resulting revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD and other gas distribution businesses also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the pass through nature of these costs.

The Company actively manages its exposure to market price risks including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, unrealized fair value gains and losses on these instruments will impact earnings. The revaluation of foreign-denominated intercompany loans also impacts earnings each quarter.

Finally, the Company is in the midst of a substantial capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company's capital expansion initiatives, including construction commencement and in-service dates, are described in *Growth Projects*.

In addition to the impacts of weather in EGD's franchise area and unrealized gains and losses outlined above, significant items that impacted the quarterly earnings included:

- Reflected in 2011 earnings are the Company's share of leak remediation costs and lost revenue associated with the Line 6A and Line 6B crude oil releases in the amounts of $6 million, $21 million, and $6 million (2010 - nil, $85 million, and $21 million) in the second, third and fourth quarters, respectively. Earnings for 2011 also reflected insurance recoveries associated with the Line 6B crude oil release of $5 million, $3 million, $13 million and $29 million in the first, second, third and fourth quarters, respectively.

- Earnings for the fourth quarter of 2011 included a charge totaling $262 million, after-tax, as a result of the discontinuance of rate regulated accounting at EGNB. This item was recognized as an extraordinary item in the Company's 2011 U.S. GAAP consolidated financial statements.
- First quarter 2011 earnings reflected positive contributions from gas gathering assets purchased in the fourth quarter of 2010.
- In April and July of 2010, the Company completed Alberta Clipper and Southern Lights Pipeline, respectively, two of the largest projects in the Company's history, and commenced recording in-service earnings from those dates forward.

NON-GAAP RECONCILIATION

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
GAAP earnings as reported	**264**	364
Significant after-tax non-recurring or non-operating factors and variances:		
Liquids Pipelines		
Canadian Mainline - Line 9 tolling adjustment	**(6)**	-
Canadian Mainline - unrealized derivative fair value gains	**(27)**	-
Gas Distribution		
EGD - (colder)/warmer than normal weather	**24**	(11)
Gas Pipelines, Processing and Energy Services		
Aux Sable - unrealized derivative fair value (gains)/loss	**(7)**	6
Energy Services - unrealized derivative fair value loss	**154**	7
Sponsored Investments		
EEP - NGL trucking and marketing investigation costs	**1**	-
EEP - unrealized derivative fair value loss	**-**	3
EEP - leak insurance recoveries	**-**	(5)
EEP - lawsuit settlement	**-**	(1)
EEP - impact of unusual weather conditions	**-**	1
Corporate		
Noverco - equity earnings adjustment	**12**	-
Other Corporate - unrealized derivative fair value gains	**(10)**	(16)
Other Corporate - foreign tax recovery	**(29)**	-
Other Corporate - unrealized foreign exchange gains on translation of intercompany balances, net	**-**	(18)
Adjusted earnings	**376**	330

OUTSTANDING SHARE DATA[1]

	Number
Preference Shares, Series A[2]	5,000,000
Preference Shares, Series B[2,3]	20,000,000
Preference Shares, Series D[2,4]	18,000,000
Preference Shares, Series F[2,5]	20,000,000
Preference Shares, Series H[2,6]	14,000,000
Preference Shares, Series J[2,7]	8,000,000
Common Shares - issued and outstanding (voting equity shares)	784,966,571
Stock Options - issued and outstanding (20,911,380 vested)	35,467,400

1 *Outstanding share data information is provided as at May 2, 2012.*
2 *Non-voting equity shares.*
3 *On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series B will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series B into an equal number of Cumulative Redeemable Preference Shares, Series C.*
4 *On March 1, 2018, and on March 1 every five years thereafter, the holders of Preference Shares, Series D will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series D into an equal number of Cumulative Redeemable Preference Shares, Series E.*
5 *On June 1, 2018, and on June 1 every five years thereafter, the holders of Preference Shares, Series F will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series F into an equal number of Cumulative Redeemable Preference Shares, Series G.*
6 *On September 1, 2018, and on September 1 every five years thereafter, the holders of Preference Shares, Series H will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series H into an equal number of Cumulative Redeemable Preference Shares, Series I.*
7 *On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series J will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series J into an equal number of Cumulative Redeemable Preference Shares, Series K.*

Effective May 25, 2011, a two-for-one stock split of the Company’s common shares was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, adjusted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended March 31,	
	2012	2011
(unaudited; millions of Canadian dollars, except per share amounts)		
Revenues		
Commodity sales	**4,838**	4,737
Gas distribution sales	**767**	753
Transportation and other services	**1,022**	1,039
	6,627	6,529
Expenses		
Commodity costs	**4,661**	4,591
Gas distribution costs	**559**	555
Operating and administrative	**632**	508
Depreciation and amortization	**290**	277
Environmental costs, net of recoveries	**3**	(33)
	6,145	5,898
	482	631
Income from equity investments	**38**	55
Other income	**86**	80
Interest expense	**(217)**	(230)
	389	536
Income taxes *(Note 10)*	**(30)**	(103)
Earnings	**359**	433
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(80)**	(67)
Earnings attributable to Enbridge Inc.	**279**	366
Preference share dividends	**(15)**	(2)
Earnings attributable to Enbridge Inc. common shareholders	**264**	364
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.35**	0.49
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.34**	0.48

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2012	2011
(unaudited; millions of Canadian dollars)		
Earnings	**359**	433
Other comprehensive income/(loss)		
Change in unrealized gain on cash flow hedges, net of tax	**160**	30
Change in unrealized gain on net investment hedges, net of tax	**9**	30
Reclassification to earnings of realized cash flow hedges, net of tax	**13**	(14)
Reclassification to earnings of unrealized cash flow hedges, net of tax	**2**	-
Other comprehensive loss from equity investees, net of tax	**(5)**	(4)
Overfunded pension adjustment, net of tax	**6**	4
Change in foreign currency translation adjustment	**(128)**	(169)
Other comprehensive income/(loss)	**57**	(123)
Comprehensive income	**416**	310
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(56)**	20
Comprehensive income attributable to Enbridge Inc.	**360**	330
Preference share dividends	**(15)**	(2)
Comprehensive income attributable to Enbridge Inc. common shareholders	**345**	328

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended March 31,	
	2012	2011
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares *(Note 6)*		
Balance at beginning of period	**1,056**	125
Shares issued	**832**	-
Balance at end of period	**1,888**	125
Common shares		
Balance at beginning of period	**3,969**	3,683
Dividend reinvestment and share purchase plan	**65**	64
Shares issued on exercise of stock options	**23**	19
Balance at end of period	**4,057**	3,766
Additional paid-in capital		
Balance at beginning of period	**242**	131
Stock-based compensation	**12**	8
Options exercised	**(4)**	(2)
Dilution gains and other	**6**	2
Issuance of treasury stock *(Note 8)*	**204**	-
Balance at end of period	**460**	139
Retained earnings		
Balance at beginning of period	**3,926**	3,993
Earnings attributable to Enbridge Inc.	**279**	366
Preference share dividends	**(15)**	(2)
Common share dividends declared	**(221)**	(188)
Dividends paid to reciprocal shareholder	**5**	5
Redemption value adjustment attributable to redeemable noncontrolling interests	**(52)**	(46)
Balance at end of period	**3,922**	4,128
Accumulated other comprehensive income/(loss) *(Note 7)*		
Balance at beginning of period	**(1,532)**	(1,027)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**81**	(35)
Balance at end of period	**(1,451)**	(1,062)
Reciprocal shareholding		
Balance at beginning of period	**(187)**	(154)
Issuance of treasury stock *(Note 8)*	**61**	-
Balance at end of period	**(126)**	(154)
Total Enbridge Inc. shareholders' equity	**8,750**	6,942
Noncontrolling interests		
Balance at beginning of period	**3,141**	2,424
Earnings attributable to noncontrolling interests	**78**	69
Other comprehensive income/(loss) attributable to noncontrolling interests		
Change in realized and unrealized gains/(loss) on cash flow hedges, net of tax	**30**	(37)
Change in foreign currency translation adjustment	**(54)**	(51)
	(24)	(88)
Comprehensive income/(loss) attributable to noncontrolling interests	**54**	(19)
Contributions	**2**	47
Distributions	**(102)**	(82)
Other	**(8)**	2
Balance at end of period	**3,087**	2,372
Total equity	**11,837**	9,314
Dividends paid per common share	**0.2825**	0.2450

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31,	
	2012	2011
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**359**	433
Depreciation and amortization	**290**	277
Unrealized loss on derivative instruments	**201**	16
Cash distributions in excess of equity earnings	**58**	20
Deferred income taxes (recovery)/expense	**(23)**	78
Other	**20**	(4)
Change in regulatory assets and liabilities	**14**	31
Change in environmental liabilities, net of recoveries	**(2)**	(119)
Change in operating assets and liabilities	**(269)**	431
	648	1,163
Investing activities		
Additions to property, plant and equipment	**(877)**	(536)
Additions to intangible assets	**(48)**	(9)
Change in construction payable	**71**	(74)
Long-term investments	**(63)**	(21)
Affiliate loans, net	**2**	2
Acquisition *(Note 4)*	**(7)**	-
Change in restricted cash	**(6)**	(9)
	(928)	(647)
Financing activities		
Net change in bank indebtedness and short-term borrowings	**(172)**	(134)
Net change in commercial paper and credit facility draws	**(220)**	(2)
Debenture and term note issues	**500**	-
Net change in Southern Lights project financing	**(5)**	(24)
Distributions to noncontrolling interests, net	**(100)**	(24)
Distributions to redeemable noncontrolling interests, net	**(12)**	(7)
Preference shares issued	**826**	-
Common shares issued	**17**	16
Preference share dividends	**(15)**	(2)
Common share dividends	**(156)**	(124)
	663	(301)
Effect of translation of foreign denominated cash and cash equivalents	**(12)**	(7)
Increase in cash and cash equivalents	**371**	208
Cash and cash equivalents at beginning of period	**723**	376
Cash and cash equivalents at end of period	**1,094**	584

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2012	December 31, 2011
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,094**	723
Restricted cash	**23**	17
Accounts receivable and other	**3,659**	4,011
Accounts receivable from affiliates	**18**	55
Inventory	**554**	823
	5,348	5,629
Property, plant and equipment, net	**29,550**	28,941
Long-term investments	**3,410**	3,160
Deferred amounts and other assets	**2,509**	2,667
Intangible assets	**741**	711
Goodwill	**437**	440
Deferred income taxes	**6**	29
	42,001	41,577
Liabilities and equity		
Current liabilities		
Bank indebtedness	**196**	102
Short-term borrowings	**282**	548
Accounts payable and other	**4,222**	4,764
Accounts payable from affiliates	**2**	48
Interest payable	**214**	185
Environmental liabilities	**129**	175
Current maturities of long-term debt	**552**	354
	5,597	6,176
Long-term debt	**19,189**	19,251
Other long-term liabilities	**2,100**	2,323
Deferred income taxes	**2,597**	2,572
	29,483	30,322
Commitments and contingencies *(Note 12)*		
Redeemable noncontrolling interests	**681**	640
Equity		
Share capital		
Preference shares *(Note 6)*	**1,888**	1,056
Common shares (785 and 781 outstanding at March 31, 2012 and December 31, 2011, respectively)	**4,057**	3,969
Additional paid-in capital	**460**	242
Retained earnings	**3,922**	3,926
Accumulated other comprehensive loss *(Note 7)*	**(1,451)**	(1,532)
Reciprocal shareholding *(Note 8)*	**(126)**	(187)
Total Enbridge Inc. shareholders' equity	**8,750**	7,474
Noncontrolling interests	**3,087**	3,141
	11,837	10,615
	42,001	41,577

See accompanying notes to the unaudited consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with United States generally accepted accounting principles (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2011 prepared in accordance with U.S. GAAP and filed with Canadian and United States securities regulators on a voluntary basis (U.S. GAAP Consolidated Financial Statements). In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the Company's financial position as at March 31, 2012 and results of operations and cash flows for the three month periods ended March 31, 2012 and 2011. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company's U.S. GAAP Consolidated Financial Statements as at and for the year ended December 31, 2011, except as described in Note 2, Changes in accounting policies. Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. As a Securities Exchange Commission registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements. The Company's 2011 Annual Report included consolidated financial statements and notes thereto for the year ended December 31, 2011 prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook. The Company's U.S. GAAP Consolidated Financial Statements for the three years ended December 31, 2011 were prepared, and voluntarily filed with securities regulators in Canada and the United States, to facilitate users understanding of the transition to U.S. GAAP.

The Company's operations and earnings for interim periods can be affected by seasonal fluctuations within the gas distribution utility business, as well as other factors such as the supply of and demand for crude oil and natural gas.

2. CHANGES IN ACCOUNTING POLICIES

REGULATION

Enbridge Gas New Brunswick

Based on amendments to the rate setting methodology outlined in a final rates and tariff regulation enacted by the Government of New Brunswick, Enbridge Gas New Brunswick (EGNB) no longer meets the criteria for rate regulated accounting. As a result, effective January 1, 2012, the Company discontinued rate regulated accounting for EGNB.

OTHER

Fair Value Measurement

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board's joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the adoption of this update impacted disclosure only, there was no impact to the Company's earnings or cash flows for the current or prior periods presented.

Statement of Comprehensive Income

Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and other comprehensive income (OCI) either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company's presentation of comprehensive income and did not impact the Company's consolidated financial statements.

Goodwill Impairment

Effective January 1, 2012, the Company adopted ASU 2011-08 which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, it is more likely than not its fair value is less than its carrying amount. Adoption of this standard does not change the current two-step goodwill impairment test.

3. SEGMENTED INFORMATION

Three months ended March 31, 2012	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**596**	**917**	**3,286**	**1,828**	**-**	**6,627**
Commodity and gas distribution costs	**-**	**(560)**	**(3,457)**	**(1,203)**	**-**	**(5,220)**
Operating and administrative	**(212)**	**(127)**	**(35)**	**(260)**	**2**	**(632)**
Depreciation and amortization	**(84)**	**(83)**	**(15)**	**(105)**	**(3)**	**(290)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**(3)**	**-**	**(3)**
	300	**147**	**(221)**	**257**	**(1)**	**482**
Income/(loss) from equity investments	**1**	**-**	**28**	**15**	**(6)**	**38**
Other income/(expense)	**4**	**(5)**	**13**	**15**	**59**	**86**
Interest expense	**(62)**	**(41)**	**(11)**	**(98)**	**(5)**	**(217)**
Income taxes recovery/(expense)	**(51)**	**(23)**	**81**	**(45)**	**8**	**(30)**
Earnings/(loss)	**192**	**78**	**(110)**	**144**	**55**	**359**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(1)**	**-**	**(1)**	**(78)**	**-**	**(80)**
Preference share dividends	**-**	**-**	**-**	**-**	**(15)**	**(15)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**191**	**78**	**(111)**	**66**	**40**	**264**
Additions to property, plant and equipment[1]	**370**	**79**	**149**	**268**	**11**	**877**

Three months ended March 31, 2011	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	459	943	2,912	2,215	-	6,529
Commodity and gas distribution costs	-	(555)	(2,852)	(1,739)	-	(5,146)
Operating and administrative	(150)	(120)	(27)	(208)	(3)	(508)
Depreciation and amortization	(81)	(79)	(19)	(96)	(2)	(277)
Environmental costs, net of recoveries	-	-	-	33	-	33
	228	189	14	205	(5)	631
Income from equity investments	-	-	27	16	12	55
Other income/(expense)	-	(5)	10	21	54	80
Interest expense	(64)	(44)	(15)	(85)	(22)	(230)
Income taxes recovery/(expense)	(28)	(38)	(9)	(36)	8	(103)
Earnings	136	102	27	121	47	433
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	-	-	(1)	(66)	-	(67)
Preference share dividends	-	-	-	-	(2)	(2)
Earnings attributable to Enbridge Inc. common shareholders	136	102	26	55	45	364
Additions to property, plant and equipment[1]	188	64	72	209	4	537

1 *Includes allowance for equity funds used during construction.*

TOTAL ASSETS

	March 31, 2012	December 31, 2011
(millions of Canadian dollars)		
Liquids Pipelines	**14,011**	12,470
Gas Distribution	**6,586**	7,189
Gas Pipelines, Processing and Energy Services	**4,950**	4,468
Sponsored Investments	**13,070**	13,453
Corporate	**3,384**	3,997
	42,001	41,577

4. ACQUISITION

SILVER STATE NORTH SOLAR PROJECT

On March 22, 2012, Enbridge acquired a 100% interest in the Silver State North Solar Project (Silver State), a solar farm located in Nevada, USA for cash consideration of $7 million (US$7 million) and an additional $183 million (US$183 million), included in Accounts payable and other, to be paid upon commencement of commercial operation, which is anticipated in May 2012.

Silver State was acquired in order to expand the Company's alternative energy business. No earnings were recognized in the three months ended March 31, 2012, or in any prior period, as the solar project has not commenced operation. As at March 31, 2012, the purchase price allocation was not complete as the Company has not completed its valuation of the acquired assets.

5. CREDIT FACILITIES

March 31, 2012	Maturity Dates[2]	Total Facilities	Credit Facility Draws[3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**25**	**275**
Gas Distribution	2012-2013	**717**	**290**	**427**
Sponsored Investments	2013-2016	**2,498**	**737**	**1,761**
Corporate	2013-2016	**6,473**	**2,394**	**4,079**
		9,988	**3,446**	**6,542**
Southern Lights project financing[1]	2013-2014	**1,505**	**1,442**	**63**
Total credit facilities		**11,493**	**4,888**	**6,605**

1 Total facilities inclusive of $60 million for debt service reserve letters of credit.
2 Total facilities include $30 million in demand facilities with no maturity date.
3 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.

Credit facilities carry a weighted average standby fee of 0.16% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2012 to 2016.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,122 million (2011 - $3,359 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

6. SHARE CAPITAL

PREFERENCE SHARES

	March 31, 2012		December 31, 2011	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Preference shares, Series A	**5**	**125**	5	125
Preference shares, Series B	**20**	**490**	20	490
Preference shares, Series D	**18**	**441**	18	441
Preference shares, Series F[1]	**20**	**490**	-	-
Preference shares, Series H[2]	**14**	**342**	-	-
Balance at end of period		**1,888**		1,056

1 Gross proceeds - $500 million; net issuance costs - $10 million.
2 Gross proceeds - $350 million; net issuance costs - $8 million.

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference shares, Series A	5.5%	1.375	25	-	-
Preference shares, Series B	4.0%	1.000	25	June 1, 2017	Series C
Preference shares, Series D	4.0%	1.000	25	March 1, 2018	Series E
Preference shares, Series F[5]	4.0%	1.000	25	June 1, 2018	Series G
Preference shares, Series H[6]	4.0%	1.000	25	September 1, 2018	Series I

1 *Fixed, cumulative, quarterly preferential dividend per share per year.*
2 *The Company may at its option, redeem all or a portion of the outstanding preference shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*
3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on the Conversion Option Date and every fifth anniversary thereafter.*
4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.40% (Series C), 2.37% (Series E), 2.51% (Series G) or 2.12% (Series I)).*
5 *A cash dividend of $0.3699 per share will be paid on June 1, 2012 to Series F shareholders of record as of May 15, 2012. The regular quarterly dividend of $0.25 per share will begin in the third quarter of 2012.*
6 *A cash dividend of $0.4247 per share will be paid on September 1, 2012 to Series H shareholders. The regular quarterly dividend of $0.25 per share will begin in the fourth quarter of 2012.*

Subsequent to March 31, 2012, the Company issued eight million Series J Preference Shares for gross proceeds of US$200 million. The 4.0% Cumulative Redeemable Preference Shares, Series J are entitled to the same dividends, and similar redemption and conversion terms as the Series B, Series D, Series F and Series H Preference Shares, except any cash payments are to be made in United States dollars. Redemption of Series J Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series K can occur on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Series K Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to US$25 multiplied by the number of days in the quarter divided by 365 and multiplying that product by the sum of the then 90-day United States Government Treasury bill rate plus 3.05%.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 26 million (2011 - 23 million), resulting from the Company's reciprocal investment in Noverco Inc. (Noverco).

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

	Three months ended March 31,	
	2012	2011
(number of shares in millions)		
Weighted average shares outstanding	**757**	750
Effect of dilutive options	**12**	8
Diluted weighted average shares outstanding	**769**	758

For the three months ended March 31, 2012, 5,759,150 anti-dilutive stock options (2011 - 4,913,200) with a weighted average exercise price of $38.32 (2011 - $28.78) were excluded from the diluted earnings per share calculation.

7. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Equity Investees	Pension Actuarial Gain/Loss Adjustment	Cumulative Translation Adjustment	Total
Balance at January 1, 2011	(66)	480	(11)	(142)	(1,288)	(1,027)
Changes during the period	63	36	(4)	5	(117)	(17)
Tax impact	(11)	(6)	-	(1)	-	(18)
	52	30	(4)	4	(117)	(35)
Balance at March 31, 2011	(14)	510	(15)	(138)	(1,405)	(1,062)
Balance at January 1, 2012	(476)	461	(28)	(286)	(1,203)	(1,532)
Changes during the period	**193**	**10**	**-**	**7**	**(74)**	**136**
Tax impact	**(48)**	**(1)**	**(5)**	**(1)**	**-**	**(55)**
	145	**9**	**(5)**	**6**	**(74)**	**81**
Balance at March 31, 2012	**(331)**	**470**	**(33)**	**(280)**	**(1,277)**	**(1,451)**

8. RECIPROCAL SHAREHOLDING

At December 31, 2011, Noverco owned an approximate 8.9% reciprocal shareholding in the common shares of the Company. On March 22, 2012, Noverco sold 22.5 million Enbridge common shares through a secondary offering, thereby reducing the Company's reciprocal shareholding to 6.0%. Both the Company's equity investment in Noverco, included in Long-term investments, and Equity have increased by $265 million, net of tax, as a result of this transaction.

9. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

The Company's earnings, cash flows, and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues denominated in United States dollars. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues denominated in United States dollars.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2016 at an average swap rate of 2.32%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2016. A total of $7,050 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company uses primarily qualifying derivative instruments to manage interest rate risk.

Commodity Price Risk
The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil and natural gas liquids (NGL). The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGL) that impact earnings from its ownership in the Aux Sable natural gas processing plant and the gathering and processing business held by Enbridge Energy Partners, L.P. (EEP).

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted stock units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the balance sheet location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at March 31, 2012 or December 31, 2011.

March 31, 2012	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments[1]
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**4**	**15**	**218**	**237**	**-**	**237**
Interest rate contracts	**-**	**-**	**10**	**10**	**(3)**	**7**
Commodity contracts	**11**	**-**	**241**	**252**	**(22)**	**230**
Other contracts	**2**	**-**	**8**	**10**	**-**	**10**
	17	**15**	**477**	**509**	**(25)**	**484**
Deferred amounts and other						
Foreign exchange contracts	**15**	**82**	**203**	**300**	**-**	**300**
Interest rate contracts	**6**	**-**	**17**	**23**	**(3)**	**20**
Commodity contracts	**10**	**-**	**108**	**118**	**(13)**	**105**
Other contracts	**3**	**-**	**3**	**6**	**-**	**6**
	34	**82**	**331**	**447**	**(16)**	**431**
Accounts payable and other						
Foreign exchange contracts	**(5)**	**-**	**(140)**	**(145)**	**-**	**(145)**
Interest rate contracts	**(402)**	**-**	**(5)**	**(407)**	**3**	**(404)**
Commodity contracts	**(29)**	**-**	**(257)**	**(286)**	**22**	**(264)**
	(436)	**-**	**(402)**	**(838)**	**25**	**(813)**
Other long-term liabilities						
Foreign exchange contracts	**(40)**	**(5)**	**(12)**	**(57)**	**-**	**(57)**
Interest rate contracts	**(262)**	**-**	**(15)**	**(277)**	**3**	**(274)**
Commodity contracts	**(38)**	**-**	**(105)**	**(143)**	**13**	**(130)**
	(340)	**(5)**	**(132)**	**(477)**	**16**	**(461)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**(26)**	**92**	**269**	**335**	**-**	**335**
Interest rate contracts	**(658)**	**-**	**7**	**(651)**	**-**	**(651)**
Commodity contracts	**(46)**	**-**	**(13)**	**(59)**	**-**	**(59)**
Other contracts	**5**	**-**	**11**	**16**	**-**	**16**
	(725)	**92**	**274**	**(359)**	**-**	**(359)**

December 31, 2011	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments[1]
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	4	15	315	334	-	334
Interest rate contracts	-	-	12	12	(4)	8
Commodity contracts	7	-	146	153	(19)	134
Other contracts	3	-	7	10	-	10
	14	15	480	509	(23)	486
Deferred amounts and other						
Foreign exchange contracts	15	79	203	297	-	297
Interest rate contracts	1	-	24	25	(3)	22
Commodity contracts	12	-	241	253	(15)	238
Other contracts	3	-	2	5	-	5
	31	79	470	580	(18)	562
Accounts payable and other						
Foreign exchange contracts	(4)	-	(275)	(279)	-	(279)
Interest rate contracts	(477)	-	(8)	(485)	4	(481)
Commodity contracts	(32)	-	(107)	(139)	19	(120)
	(513)	-	(390)	(903)	23	(880)
Other long-term liabilities						
Foreign exchange contracts	(35)	(5)	(51)	(91)	-	(91)
Interest rate contracts	(415)	-	(20)	(435)	3	(432)
Commodity contracts	(29)	-	(20)	(49)	15	(34)
	(479)	(5)	(91)	(575)	18	(557)
Total net derivative asset/(liability)						
Foreign exchange contracts	(20)	89	192	261	-	261
Interest rate contracts	(891)	-	8	(883)	-	(883)
Commodity contracts	(42)	-	260	218	-	218
Other contracts	6	-	9	15	-	15
	(947)	89	469	(389)	-	(389)

1 *As presented in the Consolidated Statements of Financial Position.*

The following table summarizes the maturity and notional principal or quantity outstanding related to the Company's derivative instruments.

March 31, 2012	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**169**	**55**	**468**	**25**	**25**	**420**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,425**	**1,865**	**2,182**	**2,583**	**2,039**	**182**
Foreign exchange contracts - Euro dollar forwards - purchase *(millions of Euros)*	**1**	**-**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**2,444**	**3,357**	**2,914**	**2,766**	**2,553**	**224**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**2,650**	**2,000**	**1,650**	**750**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**37**	**27**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**14**	**70**	**15**	**14**	**1**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**3**	**44**	**32**	**22**	**18**	**23**
Commodity contracts - NGL *(millions of barrels)*	**7**	**1**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatts per hour (MWH))*	**38**	**38**	**40**	**48**	**63**	**58**

December 31, 2011	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	58	287	468	25	25	418
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,017	1,865	2,182	2,583	2,039	180
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	3,227	3,237	2,787	2,641	2,428	215
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	2,650	2,000	1,650	750	-	-
Equity contracts *(millions of Canadian dollars)*	36	26	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	20	59	1	1	1	-
Commodity contracts - crude oil *(millions of barrels)*	11	26	17	8	7	10
Commodity contracts - NGL *(millions of barrels)*	4	1	-	-	-	-
Commodity contracts - power *(MWH)*	40	28	40	48	63	58

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income.

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**19**	(19)
Interest rate contracts	**180**	78
Commodity contracts	**(8)**	(56)
Other contracts	**(1)**	1
Net investment hedges		
Foreign exchange contracts	**3**	20
	193	24
Amount of gain/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Cash flow hedges		
Interest rate contracts[1]	**14**	4
Commodity contracts[2]	**2**	(9)
	16	(5)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Cash flow hedges		
Commodity contracts[2]	**(2)**	1
	(2)	1

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Commodity costs in the Consolidated Statements of Earnings.*

The Company estimates that $182 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on foreign exchange rates, interest rates and commodity prices when derivative contracts currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 57 months at March 31, 2012.

Non-Qualifying Derivatives
The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Foreign exchange contracts[1]	**15**	22
Interest rate contracts[2]	**(2)**	-
Commodity contracts[3]	**(203)**	(34)
Other contracts[4]	**-**	(2)
Total unrealized derivative fair value loss	**(190)**	(14)

5 Reported within Transportation and other services revenue and Other income in the Consolidated Statements of Earnings.
6 Reported within Interest expense in the Consolidated Statements of Earnings.
7 Reported within Transportation and other services revenue, Commodity costs, and Operating and administrative expense in the Consolidated Statements of Earnings.
8 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

LIQUIDITY RISK
Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments *(Note 12)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at March 31, 2012. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK
Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company generally has a policy of entering into International Securities Dealers Association (ISDA) agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparites in these particular circumstances.

The Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

(millions of Canadian dollars)	**March 31, 2012**	December 31, 2011
Canadian financial institutions	**340**	431
United States financial institutions	**174**	287
European financial institutions	**211**	257
Other[1]	**195**	112
	920	1,087

1 Other is comprised of commodity clearing house and natural gas and crude physical counterparties.

As at March 31, 2012, the Company has provided letters of credit totaling $148 million in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. The Company holds no cash collateral on asset exposures at March 31, 2012 or December 31, 2011.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates, which is reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. Also, the Company discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models, and is supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

The Company categorizes its financial instruments into one of three levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations in the Gas Pipelines, Processing and Energy Services segment. The Company does not have any other financial instruments categorized as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained. These instruments are used primarily in the Gas Pipelines, Processing and Energy Services, Sponsored Investments and Corporate segments.

The Company has also categorized the fair value of its held to maturity preferred share investment and long-term debt as Level 2. The fair value of the Company's held to maturity preferred share investment is primarily based the yield of certain Government of Canada bonds. The fair value of the Company's long term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs include long-dated derivative power contracts and NGL and natural gas contracts in the Gas Pipelines, Processing and Energy Services and Sponsored Investments segments. The Company does not have any other financial instruments categorized in Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread, as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

Fair Value of Derivatives

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

March 31, 2012	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	-	237	-	237	-	237
Interest rate contracts	-	10	-	10	(3)	7
Commodity contracts	3	100	149	252	(22)	230
Other contracts	-	10	-	10	-	10
	3	357	149	509	(25)	484
Long-term derivative assets						
Foreign exchange contracts	-	300	-	300	-	300
Interest rate contracts	-	23	-	23	(3)	20
Commodity contracts	-	65	53	118	(13)	105
Other contracts	-	6	-	6	-	6
	-	394	53	447	(16)	431
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	-	(145)	-	(145)	-	(145)
Interest rate contracts	-	(407)	-	(407)	3	(404)
Commodity contracts	-	(181)	(105)	(286)	22	(264)
	-	(733)	(105)	(838)	25	(813)
Long-term derivative liabilities						
Foreign exchange contracts	-	(57)	-	(57)	-	(57)
Interest rate contracts	-	(277)	-	(277)	3	(274)
Commodity contracts	-	(93)	(50)	(143)	13	(130)
	-	(427)	(50)	(477)	16	(461)
Total net financial asset/(liability)						
Foreign exchange contracts	-	335	-	335	-	335
Interest rate contracts	-	(651)	-	(651)	-	(651)
Commodity contracts	3	(109)	47	(59)	-	(59)
Other contracts	-	16	-	16	-	16
	3	(409)	47	(359)	-	(359)

December 31, 2011	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	-	334	-	334	-	334
Interest rate contracts	-	12	-	12	(4)	8
Commodity contracts	1	66	86	153	(19)	134
Other contracts	-	10	-	10	-	10
	1	422	86	509	(23)	486
Long-term derivative assets						
Foreign exchange contracts	-	297	-	297	-	297
Interest rate contracts	-	25	-	25	(3)	22
Commodity contracts	-	208	45	253	(15)	238
Other contracts	-	5	-	5	-	5
	-	535	45	580	(18)	562
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	-	(279)	-	(279)	-	(279)
Interest rate contracts	-	(485)	-	(485)	4	(481)
Commodity contracts	-	(59)	(80)	(139)	19	(120)
	-	(823)	(80)	(903)	23	(880)
Long-term derivative liabilities						
Foreign exchange contracts	-	(91)	-	(91)	-	(91)
Interest rate contracts	-	(435)	-	(435)	3	(432)
Commodity contracts	-	(30)	(19)	(49)	15	(34)
	-	(556)	(19)	(575)	18	(557)
Total net financial asset/(liability)						
Foreign exchange contracts	-	261	-	261	-	261
Interest rate contracts	-	(883)	-	(883)	-	(883)
Commodity contracts	1	185	32	218	-	218
Other contracts	-	15	-	15	-	15
	1	(422)	32	(389)	-	(389)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

	Fair value at March 31, 2012 *(millions of Canadian dollars)*	**Unobservable Input**	**Minimum Price**	**Maximum Price**	**Weighted Average Price**	
Commodity Contracts - Financial[1]						
Natural Gas	(4)	Forward Gas Price	2.05	3.93	2.57	$/mmbtu[3]
Crude	2	Forward Crude Price	70.14	110.10	100.70	$/barrel
NGL	(10)	Forward NGL Price	0.19	2.43	1.04	$/gallon
Power	12	Forward Power Price	48.75	88.37	74.60	$/MWH
Commodity Contracts - Physical[1]						
Natural Gas	19	Forward Gas Price	2.04	4.41	3.95	$/mmbtu[3]
Crude	9	Forward Crude Price	77.99	119.91	102.26	$/barrel
NGL	9	Forward NGL Price	0.50	2.64	1.68	$/gallon
Power	(2)	Forward Power Price	23.04	31.61	32.07	$/MWH
Commodity Options[2]						
Natural Gas	2	Option Volatility	26%	36%	31%	
NGL	10	Option Volatility	28%	62%	44%	

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 Commodity options contracts are valued using an option model valuation technique.
3 One million British thermal units (mmbtu).

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of the Company's Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices and, for option contracts, price volatility. Changes in forward commodity prices would result in significantly different fair values for long positions, with offsetting impacts to short positions. Changes in price volatility would change the value of the option contracts. Generally speaking, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

Changes in net fair value of derivative instruments classified as Level 3 in the fair value hierarchy were as follows:

	Three months ended, March 31,	
	2012	2011
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**32**	(24)
Total gains/(losses), unrealized		
Included in earnings[1]	**18**	(37)
Included in OCI	**2**	(28)
Settlements	**(5)**	12
Level 3 net derivative asset/(liability) at end of period	**47**	(77)

1 Reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at March 31, 2012 or 2011.

Fair Value of Other Financial Instruments

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. At March 31, 2012 and

December 31, 2011, all equity investments of this nature held by the Company are recognized at cost with a carrying value of $47 million at March 31, 2012 (December 31, 2011 - $56 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $580 million at March 31, 2012 (December 31, 2011 - $285 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.34% to 4.40%. At March 31, 2012, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2011 - $580 million).

At March 31, 2012, the Company's long-term debt had a carrying value of $19,741 million (December 31, 2011 - $19,605 million) and a fair value of $22,288 million (December 31, 2011 - $22,620 million).

10. INCOME TAXES

The effective income tax rate for the three months ended March 31, 2012 was 9.6% (2011 - 22.0%). Significant variances between the effective income tax rate and the weighted average Canadian statutory income tax rate were as follows:

	Three months ended March 31,	
	2012	2011
Canadian weighted average statutory tax rate	**25.7%**	25.4%
Foreign rate differential[1]	**(13.9%)**	-
Other	**(2.2%)**	(3.4%)
	9.6%	22.0%

1 The effective income tax rate decreased significantly from the prior year substantially as a result of losses arising on certain risk management activities in the Company's United States operations. The benefit was due to the higher United States income tax rate over the Canadian weighted average statutory tax rate.

11. RETIREMENT AND POSTRETIREMENT BENEFITS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees. The Company also provides other postretirement benefits (OPEB) for qualifying retired employees. Costs related to the period are presented below.

NET BENEFIT COSTS RECOGNIZED

Three months ended March 31,	2012	2011
(millions of Canadian dollars)		
Benefits earned during the period	**19**	17
Interest cost on projected benefit obligations	**13**	21
Expected return on plan assets	**(14)**	(24)
Amortization of prior service costs	**-**	1
Amortization of actuarial loss	**6**	6
Net benefit costs[1]	**24**	21

1 *Included in net benefit costs are costs related to OPEB of $3 million (2011 - $3 million).*

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Three months ended March 31,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Contributions paid	**15**	15	**1**	1
Contributions expected to be paid in the next nine months	**91**		**10**	
Total contributions expected to be paid in the year	**106**		**11**	

12. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $3,935 million which are expected to be paid within the next five years.

EEP LAKEHEAD SYSTEM LINE 6A AND 6B CRUDE OIL RELEASES

Enbridge holds an approximate 23% combined direct and indirect ownership interest in EEP. Under U.S. GAAP, Enbridge consolidates EEP and its earnings, net of noncontrolling interests, are reflected within the Sponsored Investments segment.

Line 6B Crude Oil Release

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with extended submerged oil recovery operations, including reassessment, remediation and restoration of the area and air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All of the initiatives EEP will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

The total cost estimate for this incident remains at approximately US$765 million ($129 million after-tax attributable to Enbridge) at March 31, 2012 based on a review of costs and commitments incurred coupled with the evaluation of additional information regarding requirements for environmental restoration and remediation. Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at March 31, 2012. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release
EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

In connection with this crude oil release, the cost estimate remains at US$48 million ($7 million after-tax attributable to Enbridge), before any third party or insurance recoveries and excluding fines and penalties.

EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries
EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP's remediation spending through March 31, 2012, Enbridge and its affiliates have exceeded the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

In the first quarter of 2012, EEP received insurance payments of US$50 million ($7 million after-tax attributable to Enbridge) for insurance receivable claims previously recognized as a reduction to environmental costs in 2011. At March 31, 2012, EEP had collected total insurance recoveries of US$335 million ($50 million after-tax attributable to Enbridge) for the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to EEP's insurance policies during the period that EEP deems realization of the claim for recovery to be probable. In the first quarter of 2011, EEP recognized insurance recoveries of US$35 million ($5 million after-tax attributable to Enbridge) for claims that it filed while no such recoveries were recognized during the first quarter of 2012.

Enbridge's current comprehensive insurance program, expiring April 30, 2012, has a current liability aggregate limit of US$575 million, including pollution liability. Enbridge will renew its liability insurance and expects to increase the aggregate limit of coverage effective May 1, 2012 through April 30, 2013.

Legal and Regulatory Proceedings
A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, these actions are not expected to be material. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at March 31, 2012. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

TAX MATTERS
Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

HIGHLIGHTS

	Three months ended March 31, 2012	2011
(unaudited; millions of Canadian dollars, except per share amounts)		
Earnings attributable to common shareholders		
Liquids Pipelines	**191**	136
Gas Distribution	**78**	102
Gas Pipelines, Processing and Energy Services	**(111)**	26
Sponsored Investments	**66**	55
Corporate	**40**	45
	264	364
Earnings per common share[1]	**0.35**	0.49
Diluted earnings per common share[1]	**0.34**	0.48
Adjusted earnings[2]		
Liquids Pipelines	**158**	136
Gas Distribution	**102**	91
Gas Pipelines, Processing and Energy Services	**36**	39
Sponsored Investments	**67**	53
Corporate	**13**	11
	376	330
Adjusted earnings per common share[1]	**0.50**	0.44
Cash flow data		
Cash provided by operating activities	**648**	1,163
Cash used in investing activities	**(928)**	(647)
Cash provided by/(used in) financing activities	**663**	(301)
Dividends		
Common share dividends declared	**221**	188
Dividends paid per common share[1]	**0.2825**	0.2450
Shares outstanding *(millions)*		
Weighted average common shares outstanding[1]	**757**	750
Diluted weighted average common shares outstanding[1]	**769**	758
Operating data		
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*		
Canadian Mainline[3]	**1,687**	1,602
Regional Oil Sands System[4]	**333**	329
Spearhead Pipeline	**144**	160
Gas Distribution - Enbridge Gas Distribution		
Volumes *(billions of cubic feet)*	**161**	193
Number of active customers *(thousands)*[5]	**2,001**	1,974
Heating degree days[6]		
Actual	**1,490**	1,966
Forecast based on normal weather	**1,770**	1,802
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*		
Alliance Pipeline US	**1,632**	1,677
Vector Pipeline	**1,754**	1,752
Enbridge Offshore Pipelines	**1,501**	1,751

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*
2 *Adjusted earnings represent earnings attributable to common shareholders adjusted for non-recurring or non-operating factors. Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by GAAP.*

3 Canadian Mainline includes deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.
4 Volumes are for the Athabasca mainline and Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.
5 Number of active customers is the number of natural gas consuming EGD customers at the end of the period.
6 Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD's franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.

SHAREHOLDER INFORMATION

Registrar and Transfer Agent in Canada
Inquiries regarding the Dividend Reinvestment and Share Purchase Plan, change of address, share transfer, lost certificates, dividends, and duplicate mailings should be directed to:

CIBC Mellon Trust Company
P.O. Box 7010,
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Toll free: (800) 387-0825

Dividend Reinvestment & Share Purchase Plan
Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in common shares, or to make payments to purchase additional shares in, either case free of brokerage or other charges. Share purchase cut-off for the 2012 second quarter optional cash payment to purchase additional shares is May 25, 2012.

Investor Relations
Shareholder inquiries regarding the Company's financial and operating performance should be directed to:

Investor Relations
Enbridge Inc.
3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804
Internet: www.enbridge.com

May 8, 2012

ENBRIDGE

Where energy meets people™

Enbridge common shares trade on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the United States under the trading symbol ENB.

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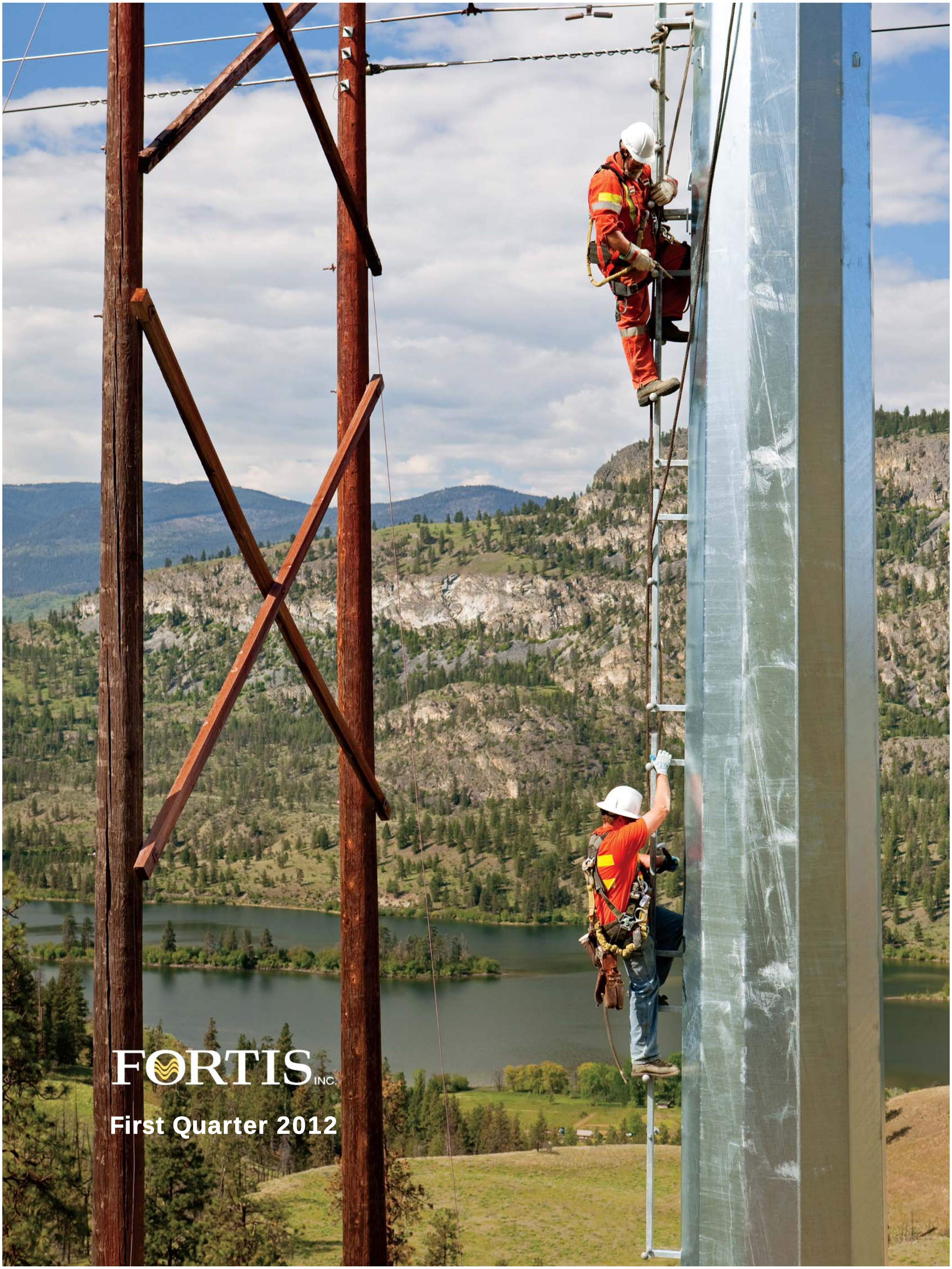

FORTIS INC.

First Quarter 2012

Dear Shareholder:

Fortis achieved first quarter net earnings attributable to common equity shareholders of $121 million, or $0.64 per share, compared to $116 million, or $0.66 per share, for the first quarter of 2011. Performance was driven by the FortisBC Energy companies. Earnings per common share were negatively impacted by an 8% increase in the weighted average number of common shares outstanding, largely associated with the public common equity offering in mid-2011. The $4 million, one-time acquisition-related expenses associated with the CH Energy Group, Inc. ("CH Energy Group") transaction in the first quarter reduced earnings per common share by $0.02.

Fortis paid a dividend of 30 cents per common share on March 1, 2012, up from 29 cents in the fourth quarter of 2011. The 3.4% increase translates into an annualized dividend of $1.20 and extends the Corporation's record of annual common share dividend increases to 39 consecutive years, the longest record of any public corporation in Canada.

Canadian Regulated Gas Utilities delivered earnings of $82 million, up $7 million from the first quarter of 2011. The increase in earnings was mainly due to: (i) seasonality of gas consumption and the timing of certain expenses in 2012; (ii) growth in energy infrastructure investment; and (iii) increased gas transportation volumes to the forestry and mining sectors. The increase was partially offset by lower-than-expected customer additions and lower capitalized allowance for funds used during construction. Due to the seasonality of the business, most of the earnings of the regulated gas utilities are realized in the first and fourth quarters.

Canadian Regulated Electric Utilities contributed earnings of $51 million compared to $52 million for the first quarter of 2011. The slight decrease in earnings was largely the result of the discontinuance of the performance-based rate-setting mechanism and the timing of certain operating expenses in 2012 at FortisBC Electric, partially offset by higher electricity sales and lower effective corporate income taxes at Newfoundland Power and Maritime Electric. Excluding the approximate $1 million gain on sale of property in the first quarter of 2011, earnings at FortisAlberta improved quarter over quarter as a result of growth in energy infrastructure investment, partially offset by the impact of a lower allowed rate of return on common shareholders' equity.

Recent regulatory decisions at FortisAlberta and the FortisBC Energy companies provide a measure of regulatory stability for our western Canadian utilities. In April 2012 regulatory decisions were received for 2012/2013 customer gas delivery rates at the FortisBC Energy companies and 2012 customer electricity distribution rates at FortisAlberta. A decision on 2012/2013 customer electricity rates at FortisBC Electric is expected mid-2012. It remains a very busy period on the regulatory front as a number of regulatory processes are underway at FortisBC, FortisAlberta and Newfoundland Power. A Generic Cost of Capital Proceeding in British Columbia to determine cost of capital, effective January 1, 2013, and a PBR rate-regulation initiative in Alberta are in progress. A Cost of Capital Application was filed by Newfoundland Power in March 2012.

Caribbean Regulated Electric Utilities contributed $3 million to earnings compared to $4 million for the first quarter of 2011. The decrease in earnings was due to higher finance charges and operating and depreciation expenses.

Non-Regulated Fortis Generation contributed $5 million to earnings, up $2 million from the first quarter of 2011. Improved performance was the result of higher production in Belize due to higher rainfall.

Fortis Properties delivered earnings of $1 million, comparable to the first quarter of 2011.

Corporate and other expenses were $21 million, or $2 million higher quarter over quarter, largely the result of CH Energy Group acquisition-related expenses incurred in the first quarter of 2012, partially offset by lower finance charges.

Cash flow from operating activities was $328 million for the quarter, up $26 million from the first quarter of 2011, driven by favourable changes in working capital, largely associated with current regulatory deferral accounts, and higher earnings.

Fortis adopted accounting principles generally accepted in the United States ("US GAAP"), effective January 1, 2012, with the restatement of prior periods. The adoption of US GAAP did not have a material impact on the Corporation's earnings per common share for the first quarter of 2012 or 2011.

In February 2012 Fortis entered into an agreement to acquire CH Energy Group for approximately US$1.5 billion, including the assumption of approximately $500 million of debt on closing. Central Hudson Gas & Electric Corporation ("Central Hudson"), the main business of CH Energy Group, is a regulated transmission and distribution utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley.

The closing of the acquisition is subject to the approval of CH Energy Group shareholders, and regulatory and other approvals, and to the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share of Fortis, excluding one-time acquisition-related expenses. In April 2012 applications were filed with the New York State Public Service Commission and Federal Energy Regulatory Commission seeking approval of the transaction. The CH Energy Group shareholder vote on the transaction is anticipated before the end of June.

Consolidated capital expenditures, before customer contributions, were approximately $229 million in the first quarter of 2012. The Customer Care Enhancement Project at FortisBC's gas business came into service in January 2012. Construction continues on the $900 million Waneta Expansion hydroelectric generating facility ("Waneta Expansion") with excavation of the intake, powerhouse and power tunnels completed. Approximately $290 million has been spent on the Waneta Expansion since construction began in late 2010.

Fortis utilities are well underway towards completing their 2012 capital projects to meet the energy needs of our customers. Our 2012 consolidated capital expenditure program is expected to be $1.3 billion. Over the next five years through 2016, our capital program is expected to total $5.5 billion. This investment should support continuing growth in earnings and dividends.

Fortis is working to close the acquisition of CH Energy Group, which is expected to occur by the end of the first quarter of 2013. We remain disciplined and patient in our pursuit of additional electric and gas utility acquisitions in the United States and Canada that will add value for Fortis shareholders.

H. Stanley Marshall
President and Chief Executive Officer
Fortis Inc.

Interim Management Discussion and Analysis

For the three months ended March 31, 2012
Dated May 2, 2012

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FORWARD-LOOKING STATEMENT

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. Financial information for 2012 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified. The MD&A should be read in conjunction with the following: (i) the interim unaudited consolidated financial statements and notes thereto for the three months ended March 31, 2012, prepared in accordance with US GAAP; (ii) the audited consolidated financial statements and notes thereto for the year ended December 31, 2011, prepared in accordance with US GAAP and voluntarily filed on the System for Electronic Document Analysis and Retrieval ("SEDAR") by Fortis on March 16, 2012; (iii) the audited consolidated financial statements and notes thereto for the year ended December 31, 2011, prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"); (iv) the "Supplemental Interim Consolidated Financial Statements for the Year Ended December 31, 2011 (Unaudited)" contained in the above-noted voluntary filing which provides a detailed reconciliation between the Corporation's interim unaudited consolidated 2011 Canadian GAAP financial statements and interim unaudited consolidated 2011 US GAAP financial statements; and (v) the MD&A for the year ended December 31, 2011 included in the Corporation's 2011 Annual Report.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the Corporation's consolidated forecast gross capital expenditures for 2012 and in total over the five-year period 2012 through 2016; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program should support continuing growth in earnings and dividends; forecast midyear rate base; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expected consolidated long-term debt maturities and repayments on average annually over the next five years; except for debt at the Exploits River Hydro Partnership ("Exploits Partnership"), the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2012; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the expected timing of the closing of the acquisition of CH Energy Group, Inc. ("CH Energy Group") by Fortis and the expectation that the acquisition will be immediately accretive to earnings per common share, excluding one-time acquisition-related expenses; and the expectation of an increase in the Corporation's committed corporate credit facility from $800 million to $1 billion.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion hydroelectric generating facility; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the Government of Belize ("GOB") for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited ("BECOL") will not be expropriated by the GOB; the expectation that the Corporation will receive fair compensation from the Government of Newfoundland and Labrador related to the expropriation of the Exploits Partnership's hydroelectric assets and water rights; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates, natural gas commodity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2014 or the adoption of International Financial Reporting Standards ("IFRS") after 2014 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology ("IT") infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; interest rate risk, including the uncertainty of the impact a continuation of a low interest rate environment may have on allowed rates of return on common shareholders' equity of the Corporation's regulated utilities; operating and maintenance risks; risk associated with changes in economic conditions; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; capital resources and liquidity risk; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; an ultimate resolution of the expropriation of the hydroelectric assets and water rights of the Exploits Partnership that differs from that which is currently expected by management; weather and seasonality risk; commodity price risk; the continued ability to hedge foreign exchange risk; counterparty risk; competitiveness of natural gas; natural gas, fuel and electricity supply risk; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risks relating to the ability to, and timing of, close of the acquisition of CH Energy Group and the realization of the benefits of the acquisition; the risk associated with defined benefit pension plan performance and funding requirements; risks related to FortisBC Energy (Vancouver Island) Inc.; environmental risks; insurance coverage risk; risk of loss of licences and permits; risk of loss of service area; risk of not being able to report under US GAAP beyond 2014 or risk that IFRS does not have an accounting standard for rate-regulated entities by the end of 2014 allowing for the recognition of regulatory assets and liabilities; risks related to changes in tax legislation; risk of failure of IT infrastructure; risk of not being able to access First Nations lands; labour relations risk; human resources risk; and risk of unexpected outcomes of legal proceedings currently against the Corporation. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A for the three months ended March 31, 2012 and for the year ended December 31, 2011.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada. Year-to-date March 31, 2012, the Corporation's electricity distribution systems met a combined peak demand of approximately 5,183 megawatts ("MW") and its gas distribution system met a peak day demand of 1,335 terajoules ("TJ"). For additional information on the Corporation's business segments, refer to Note 1 to the Corporation's interim unaudited consolidated financial statements for the three months ended March 31, 2012 and to the "Corporate Overview" section of the 2011 Annual MD&A.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably at the lowest reasonable cost and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation.

Generally under COS regulation, the respective regulatory authority sets customer gas and/or electricity rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). Generally, the ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. As such, earnings of regulated utilities are generally impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) timing differences within an annual financial reporting period, between when actual expenses are incurred and when they are recovered from customers in rates. When forward test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Pending Acquisition of CH Energy Group, Inc.: On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group, Inc. ("CH Energy Group") for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing (the "Acquisition"). CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated transmission and distribution ("T&D") utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The closing of the Acquisition, which is expected by the end of the first quarter of 2013, is subject to receipt of CH Energy Group's common shareholders' approval, regulatory and other approvals, and the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share of Fortis, excluding one-time acquisition-related expenses. Fortis and CH Energy Group filed a joint petition with the New York State Public Service Commission in April 2012 for approval of the acquisition of all of the outstanding stock of CH Energy Group by Fortis and, indirectly, ownership of Central Hudson, and related transactions. The vote on the acquisition by CH Energy Group's shareholders is expected to occur mid-2012. Also, an application was filed in April 2012 with the Federal Energy Regulatory Commission seeking similar approvals.

Transition to US GAAP: In June 2011 the Ontario Securities Commission issued a decision allowing Fortis and its reporting issuer subsidiaries to prepare their financial statements, effective January 1, 2012 through to December 31, 2014, in accordance with US GAAP without qualifying as U.S. Securities and Exchange Commission ("SEC") Issuers pursuant to Canadian securities laws. The Corporation and its reporting issuer subsidiaries, therefore, adopted US GAAP as opposed to International Financial Reporting Standards ("IFRS") on January 1, 2012. Earnings recognized under US GAAP are more closely aligned with earnings recognized under Canadian GAAP, mainly due to the continued recognition of regulatory assets and liabilities under US GAAP. A transition to IFRS would likely have resulted in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities and significant volatility in the Corporation's consolidated earnings. On March 16, 2012, Fortis voluntarily prepared and filed audited consolidated US GAAP financial statements for the year ended December 31, 2011, with 2010 comparatives. Also included in the voluntary filing were: (i) a detailed reconciliation between the Corporation's audited consolidated Canadian GAAP and audited consolidated US GAAP financial statements for fiscal 2011, including 2010 comparatives; and (ii) a detailed reconciliation between the Corporation's 2011 interim unaudited consolidated Canadian GAAP and 2011 interim unaudited consolidated US GAAP financial statements. For further information, refer to the "Changes in Accounting Policies" section of this MD&A.

Expropriated Assets - Belize Electricity: There were no material changes during the first quarter of 2012 with respect to matters pertaining to the expropriation of Belize Electricity from those disclosed in the Corporation's 2011 Annual MD&A. Court proceedings continue in the Belize Supreme Court in respect of the Corporation's challenge to the expropriation.

FINANCIAL HIGHLIGHTS

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's business is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Key financial highlights for the first quarters ended March 31, 2012 and March 31, 2011 are provided in the following table.

Consolidated Financial Highlights (Unaudited)	**Quarter Ended March 31**		
($ millions, except for common share data)	**2012**	2011	Variance
Revenue	**1,149**	1,159	(10)
Energy Supply Costs	**566**	603	(37)
Operating Expenses	**214**	210	4
Depreciation and Amortization	**119**	103	16
Other Income (Expenses), Net	**(3)**	8	(11)
Finance Charges	**91**	92	(1)
Income Taxes	**23**	31	(8)
Net Earnings	**133**	128	5
Net Earnings Attributable to:			
Non-Controlling Interests	**1**	1	-
Preference Equity Shareholders	**11**	11	-
Common Equity Shareholders	**121**	116	5
Net Earnings	**133**	128	5
Basic Earnings per Common Share *($)*	**0.64**	0.66	(0.02)
Diluted Earnings per Common Share *($)*	**0.62**	0.64	(0.02)
Weighted Average Number of Common Shares Outstanding *(# millions)*	**189.0**	175.0	14.0
Cash Flow from Operating Activities	**328**	302	26

Factors Contributing to Revenue Variance

Unfavourable

- Lower commodity cost of natural gas charged to customers
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower average gas consumption by residential and commercial customers, partially offset by higher gas transportation volumes to the forestry and mining sectors

Favourable

- An increase in gas delivery rates and the base component of electricity rates at the regulated utilities in western Canada, consistent with interim rate decisions, reflecting ongoing investment in energy infrastructure and forecasted higher expenses recoverable from customers
- Growth in the number of customers, driven by FortisAlberta, and higher average electricity consumption at most of the regulated electric utilities
- The flow through in customer electricity rates of overall higher energy supply costs, driven by Caribbean Utilities
- Increased non-regulated hydroelectric production in Belize, due to higher rainfall
- Higher Hospitality revenue at Fortis Properties, driven by contribution from the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011

Factors Contributing to Energy Supply Costs Variance

Favourable
- Lower commodity cost of natural gas
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower average gas consumption
- Lower purchased power costs at Maritime Electric

Unfavourable
- Increased fuel prices at Caribbean Utilities and purchased power costs at FortisBC Electric
- Higher electricity sales

Factors Contributing to Operating Expenses Variance

Unfavourable
- General inflationary and employee-related cost increases at the Corporation's regulated utilities and timing of expenditures at FortisBC Electric
- Operating expenses associated with the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011

Favourable
- Lower operating expenses at the FortisBC Energy companies, mainly due to the accrual of non-asset retirement obligation ("non-ARO") removal costs in depreciation, effective January 1, 2012, and lower customer care-related costs as a result of insourcing the customer care function, effective January 1, 2012
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011

Factors Contributing to Depreciation and Amortization Costs Variance

Unfavourable
- Continued investment in energy infrastructure
- Increased depreciation at the FortisBC Energy companies, mainly due to the accrual of non-ARO removal costs in depreciation, effective January 1, 2012, as discussed above

Favourable
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011

Factors Contributing to Other Income (Expenses), Net Variance

Unfavourable
- Approximately $4 million of costs incurred in the first quarter of 2012 related to the pending acquisition of CH Energy Group
- Lower capitalized equity component of allowance for funds used during construction ("AFUDC"), mainly at the FortisBC Energy companies and FortisBC Electric
- An approximate $1.5 million foreign exchange loss associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's former investment in Belize Electricity
- An approximate $1 million gain on the sale of property at FortisAlberta during the first quarter of 2011

Factors Contributing to Finance Charges Variance

Favourable
- Higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion hydroelectric generating facility ("Waneta Expansion")
- Lower corporate credit facility borrowings, due to the repayment of borrowings during the third quarter of 2011 with a portion of the proceeds from the public common equity offering in mid-2011
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower short-term borrowings at the regulated utilities

Unfavourable
- Higher long-term debt levels in support of the utilities' capital expenditure programs
- Lower capitalized debt component of AFUDC mainly at the FortisBC Energy companies and FortisBC Electric

Factors Contributing to Income Taxes Variance

Favourable
- Lower statutory income tax rates
- Lower earnings before income taxes
- Higher deductions for income tax purposes compared to accounting purposes

Factors Contributing to Earnings Variance

Favourable
- Increased earnings at the FortisBC Energy companies, mainly due to seasonality of gas consumption and the timing of certain expenses in 2012, combined with growth in energy infrastructure investment and higher gas transportation volumes to the forestry and mining sectors. The increase was partially offset by lower-than-expected customer additions and lower capitalized AFUDC.
- Increased non-regulated hydroelectric production in Belize, due to higher rainfall
- Higher earnings at Newfoundland Power and Maritime Electric, mainly due to increased electricity sales and lower effective corporate income taxes

Unfavourable
- The expiry of the performance-based rate-setting ("PBR") mechanism on December 31, 2011 at FortisBC Electric and the timing of certain operating expenses at the utility in 2012
- Higher corporate expenses due to approximately $4 million of costs incurred in the first quarter of 2012 related to the pending acquisition of CH Energy Group and a $1.5 million foreign exchange loss, partially offset by lower finance charges
- An approximate $1 million gain on the sale of property at FortisAlberta during the first quarter of 2011

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders (Unaudited)	**Quarter Ended March 31**		
($ millions)	**2012**	2011	Variance
Regulated Gas Utilities - Canadian			
FortisBC Energy Companies	**82**	75	7
Regulated Electric Utilities - Canadian			
FortisAlberta	***21***	*21*	-
FortisBC Electric	***16***	*19*	*(3)*
Newfoundland Power	***7***	*6*	*1*
Other Canadian Electric Utilities	***7***	*6*	*1*
	51	52	(1)
Regulated Electric Utilities - Caribbean	**3**	4	(1)
Non-Regulated - Fortis Generation	**5**	3	2
Non-Regulated - Fortis Properties	**1**	1	-
Corporate and Other	**(21)**	(19)	(2)
Net Earnings Attributable to Common Equity Shareholders	**121**	116	5

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Regulatory Highlights" section of this MD&A. A discussion of the financial results of the Corporation's reporting segments is as follows.

REGULATED GAS UTILITIES - CANADIAN

FORTISBC ENERGY COMPANIES [(1)]

Gas Volumes by Major Customer Category (Unaudited) (TJ)	Quarter Ended March 31 2012	2011	Variance
Core – Residential and Commercial	**48,532**	50,448	(1,916)
Industrial	**1,771**	1,888	(117)
Total Sales Volumes	**50,303**	52,336	(2,033)
Transportation Volumes	**21,469**	20,484	985
Throughput under Fixed Revenue Contracts	**607**	476	131
Total Gas Volumes	**72,379**	73,296	(917)

(1) Includes FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI")

Factors Contributing to Gas Volumes Variances

Unfavourable

- Lower average gas consumption by residential and commercial customers as a result of overall warmer temperatures

Favourable

- Higher gas transportation volumes reflecting improved economic conditions favourably affecting the forestry and mining sectors

Net customer additions were 1,000 during the first quarter of 2012 compared to 1,400 during the same quarter in 2011. Net customer additions decreased due to lower building activity during 2012. With the implementation of the new Customer Care Enhancement Project on January 1, 2012, the FortisBC Energy companies changed their definition of a customer. As a result of this change, FEI adjusted its customer count downwards by approximately 17,000, effective January 1, 2012. As at March 31, 2012, the total number of customers served by the FortisBC Energy companies was approximately 939,000.

The FortisBC Energy companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and the commodity cost of natural gas from those forecast to set residential and commercial customer gas rates do not materially affect earnings.

Seasonality has a material impact on the earnings of the FortisBC Energy companies as a major portion of the gas distributed is used for space heating. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters.

Financial Highlights (Unaudited) ($ millions)	Quarter Ended March 31 2012	2011	Variance
Revenue	**548**	574	(26)
Earnings	**82**	75	7

Factors Contributing to Revenue Variance

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Lower average gas consumption by residential and commercial customers

Favourable

- An interim increase in the delivery component of customer rates, mainly due to ongoing investment in energy infrastructure and forecasted higher expenses recoverable from customers. A decision on 2012 and 2013 customer delivery rates was received by the FortisBC Energy companies in April 2012.
- Higher gas transportation volumes to the forestry and mining sectors

Factors Contributing to Earnings Variance

Favourable

- The seasonality of gas consumption and the timing of certain expenses in 2012. Revenue is recognized based on seasonal gas consumption while certain operating expenses, as well as depreciation, are generally incurred evenly throughout the year.
- Rate base growth, due to continued investment in energy infrastructure
- Higher gas transportation volumes to the forestry and mining sectors

Unfavourable

- Lower-than-expected customer additions in the first quarter of 2012
- Lower capitalized AFUDC, due to a lower asset base under construction during the first quarter of 2012

REGULATED ELECTRIC UTILITIES - CANADIAN

FORTISALBERTA

Financial Highlights (Unaudited)	**Quarter Ended March 31**		
	2012	2011	Variance
Energy Deliveries *(gigawatt hours ("GWh"))*	**4,482**	4,402	80
Revenue *($ millions)*	**108**	100	8
Earnings *($ millions)*	**21**	21	-

Factors Contributing to Energy Deliveries Variance

Favourable

- Growth in the number of customers, with the total number of customers increasing by approximately 8,000 quarter over quarter, driven by favourable economic conditions
- Higher average consumption by the oilfield sector, due to increased activity mainly as a result of high market prices for oil

Unfavourable

- Lower average consumption by residential customers due to warmer-than-average temperatures during the first quarter of 2012

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Factors Contributing to Revenue Variance

Favourable

- An interim increase in customer electricity distribution rates, effective January 1, 2012, reflecting the parameters of the Negotiated Settlement Agreement ("NSA") filed by FortisAlberta in November 2011 for 2012 rates. The interim rate increase was driven primarily by ongoing investment in energy infrastructure and forecasted higher expenses recoverable from customers. A decision on the NSA was received in April 2012 approving the interim increase in customer rates as final.
- Growth in the number of customers

Unfavourable

- A lower allowed ROE quarter over quarter. The cumulative impact on revenue, from January 1, 2011, of the decrease in the allowed ROE to 8.75%, effective for both 2011 and 2012, from 9.00% for 2010 was recognized during the fourth quarter of 2011, when the regulatory decision was received.

Factors Contributing to Earnings Variance

Favourable

- Rate base growth, due to continued investment in energy infrastructure

Unfavourable

- An approximate $1 million gain on the sale of property during the first quarter of 2011
- Lower-than-expected number of customers and lower-than-expected energy consumption by residential customers in the first quarter of 2012
- A lower allowed ROE quarter over quarter

FORTISBC ELECTRIC [(1)]

Financial Highlights (Unaudited)	Quarter Ended March 31		
	2012	2011	Variance
Electricity Sales *(GWh)*	**909**	905	4
Revenue *($ millions)*	**87**	83	4
Earnings *($ millions)*	**16**	19	(3)

[(1)] Includes the regulated operations of FortisBC Inc. and operating, maintenance and management services related to the Waneta, Brilliant and Arrow Lakes hydroelectric generating plants and the distribution system owned by the City of Kelowna. Excludes the non-regulated generation operations of FortisBC Inc.'s wholly owned partnership, Walden Power Partnership

Factor Contributing to Electricity Sales Variance

Favourable

- Growth in the number of customers

Factors Contributing to Revenue Variance

Favourable

- An interim, refundable increase in customer electricity rates, effective January 1, 2012, mainly reflecting ongoing investment in energy infrastructure and forecasted higher expenses recoverable from customers
- A 1.4% increase in customer electricity rates, effective June 1, 2011, as a result of the flow through to customers of increased purchased power costs charged to FortisBC Electric by BC Hydro
- The 0.4% increase in electricity sales

Factors Contributing to Earnings Variance

Unfavourable

- The expiry of the PBR mechanism on December 31, 2011. During the first quarter of 2011, lower-than-expected costs, primarily purchased power costs, were shared equally between customers and FortisBC Electric under the PBR mechanism. Pursuant to the Company's 2012-2013 Revenue Requirements Application ("RRA"), which is subject to regulatory approval, variances between actual purchased power costs and certain other costs and those used to set customer electricity rates are subject to full deferral account treatment and, therefore, did not impact FortisBC Electric's earnings for the first quarter of 2012.
- Increased operating expenses due to the timing of expenditures in 2012
- Lower capitalized AFUDC due to a lower asset base under construction during the first quarter of 2012

Favourable

- Rate base growth, due to continued investment in energy infrastructure

NEWFOUNDLAND POWER

Financial Highlights (Unaudited)	Quarter Ended March 31		
	2012	2011	Variance
Electricity Sales *(GWh)*	**1,914**	1,834	80
Revenue *($ millions)*	**192**	183	9
Earnings *($ millions)*	**7**	6	1

Factors Contributing to Electricity Sales Variance

Favourable
- Growth in the number of customers
- Higher average consumption, reflecting the higher concentration of electric-versus-oil heating in new home construction combined with economic growth

Factors Contributing to Revenue Variance

Favourable
- The 4.4% increase in electricity sales

Unfavourable
- Revenue during the first quarter of 2011 included amounts related to support structure arrangements, which were in place with Bell Aliant Inc. ("Bell Aliant") during 2011, associated with the joint-use poles held for sale to Bell Aliant. The joint-use poles were sold in October 2011.

Factors Contributing to Earnings Variance

Favourable
- Electricity sales growth
- Lower effective corporate income taxes, primarily due to a lower allocation of Part VI.1 tax to Newfoundland Power and a lower statutory income tax rate

Unfavourable
- The impact of the support structure arrangements with Bell Aliant during 2011, as discussed above

OTHER CANADIAN ELECTRIC UTILITIES (1)

Financial Highlights (Unaudited)	Quarter Ended March 31		
	2012	2011	Variance
Electricity Sales *(GWh)*	**645**	654	(9)
Revenue *($ millions)*	**91**	91	-
Earnings *($ millions)*	**7**	6	1

(1) Includes Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power, Cornwall Electric and Algoma Power.

Factors Contributing to Electricity Sales Variance

Unfavourable
- Lower average consumption by residential and industrial customers in Ontario, reflecting more moderate temperatures and weakened economic conditions in the region

Favourable
- Growth in the number of residential customers and an increase in the number of residential customers using electricity for home heating on Prince Edward Island ("PEI")
- Higher average consumption by commercial customers in the agricultural processing sector on PEI

Factors Contributing to Revenue Variance

Favourable
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario
- Increased electricity sales on PEI, for the reason discussed above

Unfavourable
- Lower basic component of customer rates at Maritime Electric, effective March 1, 2011, associated with the recovery of energy supply costs
- Decreased electricity sales in Ontario, for the reason discussed above

Factors Contributing to Earnings Variance

Favourable
- Lower effective corporate income taxes, primarily due to higher deductions taken for income tax purposes compared to accounting purposes and lower statutory income tax rates
- Increased electricity sales on PEI

REGULATED ELECTRIC UTILITIES - CARIBBEAN [1]

Financial Highlights (Unaudited)	Quarter Ended March 31		
	2012	2011	Variance
Average US:CDN Exchange Rate [2]	**1.00**	0.99	0.01
Electricity Sales *(GWh)*	**166**	257	(91)
Revenue *($ millions)*	**63**	75	(12)
Earnings *($ millions)*	**3**	4	(1)

[1] Includes Caribbean Utilities on Grand Cayman, Cayman Islands, in which Fortis holds an approximate 60% controlling interest; wholly owned Fortis Turks and Caicos; and the financial results of the Corporation's approximate 70% controlling interest in Belize Electricity up to June 20, 2011. Effective June 20, 2011, the Government of Belize expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. For further information, refer to the "Key Trends and Risks – Expropriated Assets" and "Business Risk Management – Investment in Belize" sections of the 2011 Annual MD&A.

[2] The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Factors Contributing to Electricity Sales Variance

Unfavourable
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. Excluding Belize Electricity, electricity sales increased approximately 1.7% quarter over quarter.
- Cooler temperatures and higher rainfall experienced on Grand Cayman, which decreased air conditioning load

Favourable
- Growth in the number of customers in Grand Cayman and the Turks and Caicos Islands
- Warmer temperatures experienced in the Turks and Caicos Islands, which increased air conditioning load

Factors Contributing to Revenue Variance

Unfavourable
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011

Favourable
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the cost of fuel
- Higher electricity sales, excluding Belize Electricity

Factors Contributing to Earnings Variance

Unfavourable

- Higher depreciation expense and finance charges, excluding Belize Electricity, largely due to investment in utility capital assets
- Increased operating expenses, excluding Belize Electricity, mainly associated with higher insurance expense and employee-related costs at Caribbean Utilities and the timing of capital projects at Fortis Turks and Caicos

Favourable

- Higher electricity sales, excluding Belize Electricity
- Lower energy supply costs at Fortis Turks and Caicos, mainly due to more fuel-efficient production realized with the commissioning of new generation units at the utility

NON-REGULATED - FORTIS GENERATION [(1)]

Financial Highlights (Unaudited)	Quarter Ended March 31		
	2012	2011	Variance
Energy Sales *(GWh)*	**88**	76	12
Revenue *($ millions)*	**9**	7	2
Earnings *($ millions)*	**5**	3	2

[(1)] Includes the financial results of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State, with a combined generating capacity of 139 MW, mainly hydroelectric

Factors Contributing to Energy Sales Variance

Favourable

- Increased production in Belize, due to higher rainfall

Unfavourable

- Decreased production in Upper New York State, due to a generating facility being out of service

Factor Contributing to Revenue and Earnings Variances

Favourable

- Increased production in Belize

In May 2011 the generator at Moose River's hydroelectric generating facility in Upper New York State sustained electrical damage. Equipment and business interruption insurance claims are ongoing. Revenue for the first quarter of 2012 reflects the accrual of insurance proceeds related to the loss of earnings for the first quarter of 2012 associated with the shutdown of the facility. The generator is under repair and the facility is expected to become operational in May 2012.

NON-REGULATED - FORTIS PROPERTIES [(1)]

Financial Highlights (Unaudited)	Quarter Ended March 31		
	2012	2011	Variance
Hospitality - Revenue per Available Room ("RevPAR") *($)*	**66.54**	63.29	3.25
Real Estate - Occupancy Rate *(as at, %)*	**92.2**	94.3	(2.1)
Hospitality Revenue *($ millions)*	**35**	33	2
Real Estate Revenue *($ millions)*	**17**	17	-
Total Revenue *($ millions)*	**52**	50	2
Earnings *($ millions)*	**1**	1	-

[(1)] Fortis Properties owns and operates 22 hotels, collectively representing 4,300 rooms, in eight Canadian provinces and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

Factors Contributing to Revenue Variance

Favourable

- A 5.1% increase in RevPAR at the Hospitality Division, driven by contribution from the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011
- Excluding the impact of the Hilton Suites Winnipeg Airport hotel, RevPAR was $64.85 for the first quarter of 2012, an increase of 2.5% quarter over quarter. RevPAR increased due to an overall 3.1% increase in the average daily room rate, partially offset by an overall 0.6% decrease in hotel occupancy. The average daily room rate increased in all regions. Hotel occupancy in Atlantic Canada and central Canada decreased, while occupancy in western Canada increased.

Factors Contributing to Earnings Variance

Favourable

- Contribution from the Hilton Suites Winnipeg Airport hotel

Unfavourable

- A $0.5 million gain on the sale of the Viking Mall during the first quarter of 2011

CORPORATE AND OTHER [(1)]

Financial Highlights (Unaudited) *($ millions)*	**Quarter Ended March 31**		
	2012	2011	Variance
Revenue	**6**	6	-
Operating Expenses	**3**	2	1
Depreciation and Amortization	**1**	1	-
Other Income (Expenses), Net	**(5)**	-	(5)
Finance Charges	**11**	14	(3)
Income Tax Recovery	**(4)**	(3)	(1)
	(10)	(8)	(2)
Preference Share Dividends	**11**	11	-
Net Corporate and Other Expenses	**(21)**	(19)	(2)

[(1)] Includes Fortis net corporate expenses, net expenses of non-regulated FortisBC Holdings Inc. ("FHI") corporate-related activities and the financial results of FHI's non-regulated wholly owned subsidiary FortisBC Alternative Energy Services Inc. and FHI's 30% ownership interest in CustomerWorks Limited Partnership ("CWLP"). The contracts between CWLP and the FortisBC Energy companies ended on December 31, 2011.

Factors Contributing to Net Corporate and Other Expenses Variance

Unfavourable

- Increased other expenses, net of other income, driven by approximately $4 million of costs incurred in the first quarter of 2012 related to the pending acquisition of CH Energy Group and an approximate $1.5 million foreign exchange loss associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's former investment in Belize Electricity

Favourable

- Lower finance charges primarily due to: (i) higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion; (ii) lower credit facility borrowings due to the repayment of borrowings during the third quarter of 2011 with a portion of the proceeds from the public common equity offering in mid-2011; and (iii) the conversion of the Corporation's US$40 million unsecured convertible subordinated debentures into common shares in November 2011

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities for the first quarter of 2012 are summarized as follows.

NATURE OF REGULATION

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2010	2011	2012	Supportive Features Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROE
FEI	British Columbia Utilities Commission ("BCUC")	40	9.50	9.50	9.50	FEI: Prior to January 1, 2010, 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009 with a two-year phase-out
FEVI	BCUC	40	10.00	10.00	10.00	
FEWI	BCUC	40	10.00	10.00	10.00	ROEs established by the BCUC Future Test Year
FortisBC Electric	BCUC	40	9.90	9.90	9.90	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC Future Test Year
FortisAlberta	Alberta Utilities Commission ("AUC")	41	9.00	8.75	8.75	COS/ROE ROE established by the AUC Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	9.00 +/- 50 bps	8.38 +/- 50 bps	8.38 +/- 50 bps (1)	COS/ROE The allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields. The formula has been suspended for 2012. Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	9.75	9.75	9.75	COS/ROE Future Test Year
FortisOntario Electric	Ontario Energy Board ("OEB")					Canadian Niagara Power - COS/ROE
	Canadian Niagara Power	40	8.01	8.01	8.01 (2)	Algoma Power - COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") Program
	Algoma Power	40	8.57	9.85	9.85 (2)	
	Franchise Agreement Cornwall Electric					Cornwall Electric - Price cap with commodity cost flow through Canadian Niagara Power - 2009 historical test year for 2010, 2011 and 2012 Algoma Power - 2007 historical test year for 2010; 2011 test year for 2011 and 2012

NATURE OF REGULATION (cont'd)

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2010	2011	2012	Supportive Features Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROA
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	7.75 - 9.75	7.75 - 9.75	7.25 - 9.25	Rate-cap adjustment mechanism ("RCAM") based on published consumer price indices The Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane.
						Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings to the Interim Government of the Turks and Caicos Caicos Islands ("Interim Government")	N/A	17.50 [(3)]	17.50 [(3)]	17.50 [(3)]	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year.
						Future Test Year

(1) Interim, pending the review of Newfoundland Power's cost of capital in 2012 by the PUB

(2) Based on the ROE automatic adjustment formula, the allowed ROE for electric utilities in Ontario is 9.12% for utilities with rates effective May 1, 2012. This ROE is not applicable to regulated electric utilities in Ontario until they are scheduled to file their next full COS rate applications. As a result, the allowed ROE of 9.12% is not applicable to Canadian Niagara Power or Algoma Power for 2012.

(3) Amount provided under licence. ROA achieved in 2010 and 2011 was significantly lower than the ROA allowed under the licence due to significant investment occurring at the utility and the lack of rate relief thereto.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• FEI and FEWI review with the BCUC natural gas and propane commodity prices every three months and midstream costs annually, in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane and contracting for midstream resources, such as third-party pipeline and/or storage capacity. The commodity cost of natural gas and propane and midstream costs are flowed through to customers without markup. The bundled rate charged to FEVI customers includes a component to recover approved gas costs and is set annually. In order to ensure that the balance in the Commodity Cost Reconciliation Account is recovered on a timely basis, FEI and FEWI prepare and file quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas. These rate adjustments ignore the temporal effect of derivative valuation adjustments on the balance sheet and, instead, reflect the forward forecast of gas costs over the recovery period. • Effective January 1, 2012, interim rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas increased by approximately 3% and interim rates for FEWI's residential customers increased by approximately 6%, reflecting changes in delivery and midstream costs. Interim approval was also received to hold FEVI customer rates at 2011 levels, effective January 1, 2012. Natural gas commodity rates were unchanged, effective January 1, 2012. • Effective April 1, 2012, due to a decrease in natural gas commodity rates, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 10% and rates for residential customers at FEWI decreased approximately 6%, following the BCUC's quarterly review of commodity costs. • In July 2011 FEVI received a BCUC decision approving the option for two First Nations bands to invest up to a combined 15% in the equity component of the capital structure of the liquefied natural gas ("LNG") storage facility on Vancouver Island. In late 2011 each band exercised its option and each invested approximately $6 million in equity in the LNG storage facility on January 1, 2012.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FEI/FEVI/FEWI (cont'd)	• In October 2011 FEI filed an application for approval of expenditures of approximately $5 million on facilities required to provide thermal energy services to 19 buildings in the Delta School District located in the Greater Vancouver area and to provide thermal energy upgrades to the buildings over the next two years. When completed, FEI will own, operate and maintain the new thermal plants and charge the Delta School District a single rate for thermal energy consumed. In March 2012 the BCUC issued its decision granting FEI a Certificate of Public Convenience and Necessity ("CPCN") related to the capital expenditures, on the condition that FEI assign the related third-party contracts associated with the above-noted project to a regulated company affiliated with FEI, which FEI has complied with. Approval of the related customer rates and rate design, as filed by FEI, were denied and the Company refiled revised rates and rate design in April 2012, as invited by the BCUC, with a decision pending from the BCUC. • In February 2012 the BCUC approved FEI's amended application for a general tariff for the provision of compressed natural gas ("CNG") and LNG for transportation vehicles. In February 2012 FEI subsequently filed for a CPCN to construct and operate CNG fueling station infrastructure, to be in service October 2012, along with a long-term contract with a counterparty for the supply of CNG in accordance with the approved general tariff. A decision on the above matter is expected in May 2012. • In November 2011 FEI, FEVI and FEWI filed an application with the BCUC for the amalgamation of the three companies into one legal entity and for the implementation of common rates and services for the utilities' customers across British Columbia, effective January 1, 2013. In late 2011 the utilities temporarily suspended their application while they provide additional information to the BCUC, as requested. In April 2012 the utilities refiled their application. The amalgamation requires approval by the BCUC and consent of the Government of British Columbia. • In November 2011 the BCUC issued preliminary notification to public utilities subject to its regulation, including the FortisBC gas and electric utilities, that it planned to initiate a Generic Cost of Capital ("GCOC") Proceeding in early 2012. In February 2012 the BCUC established that a GCOC Proceeding would take place and, in March 2012, provided for comment a preliminary scoping document outlining the matters to be examined by the proceeding. In April 2012 the BCUC issued a final scoping document identifying the items that will be reviewed as part of the GCOC Proceeding, which include: (i) the appropriate cost of capital for a benchmark low-risk utility effective January 1, 2013, which includes capital structure, ROE and interest on debt; (ii) the establishment of a benchmark ROE based on a benchmark low-risk utility effective from January 1, 2013 through December 31, 2013 for the initial transition year; (iii) the determination of whether a return to an ROE automatic adjustment mechanism is warranted, which would be implemented January 1, 2014 or, if not, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013; (iv) a generic methodology on how to establish each utility's cost of capital in reference to the cost of capital for a benchmark low-risk utility; (v) a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt; and (vi) for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism and, if not warranted, a future regulatory process will be set on how the deemed interest rate would be adjusted beyond December 31, 2013. The GCOC Proceeding is not intended to set each utility's risk premium. As part of the GCOC Proceeding, the BCUC will retain an independent consultant to report on regulatory practices in Canadian jurisdictions. The GCOC Proceeding will occur in 2012. The result of the GCOC Proceeding could materially impact the earnings of the FortisBC Energy Companies and FortisBC Electric. • In April 2012 the BCUC issued its decision on the FortisBC Energy companies' 2012-2013 RRAs. The interim increases in customer rates, effective January 1, 2012, at FEI and FEWI reflected the applied for rate increases. The above-noted decision is expected to result in a decrease in customer delivery rates at FEI and FEWI in the range of 1%-2% from the interim rates. In its decision, the BCUC approved FEVI's 2012 and 2013 customer rates to remain unchanged from 2011 customer rates. The difference between interim and final customer rates at FEI and FEWI will be refunded to customers over the remainder of 2012. The final approved customer delivery rates reflect allowed ROEs and capital structure unchanged from 2011. The final rate increases were driven by ongoing investment in energy infrastructure focused on system integrity and reliability, and forecasted increased operating expenses associated with inflation, a heightened focus on safety and security of the natural gas system, and increasing compliance with codes and regulations.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisBC Electric	• In June 2011 FortisBC Electric filed its 2012-2013 RRA, which included its 2012-2013 Capital Expenditure Plan and its Integrated System Plan ("ISP"). The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term Demand Side Management Plan. FortisBC Electric requested an interim 4% increase in customer electricity rates effective January 1, 2012 and a 6.9% increase effective January 1, 2013. The rate increases are due to ongoing investment in energy infrastructure, including increased costs of financing the investment, as well as increased purchased power costs. The requested customer rates reflect an allowed ROE and capital structure unchanged from 2011. In addition to a continuation of deferral accounts and flow-through treatments that existed under the PBR agreement, which expired at the end of 2011, the 2012–2013 RRA proposes deferral accounts and flow-through treatment for variances from the forecast used to set customer rates for electricity revenue, purchased power costs and certain other costs. • In November 2011 FortisBC Electric filed an updated 2012-2013 RRA to include updated financial estimates and forecasts, resulting in a revised requested increase in customer rates of 1.5%, effective January 1, 2012, and 6.5%, effective January 1, 2013. The revised application assumes forecast midyear rate base of approximately $1,146 million for 2012 and $1,215 million for 2013. An oral hearing process occurred in March 2012 and a decision is expected mid-2012. The interim, refundable customer rate increase of 1.5%, effective January 1, 2012, was approved by the BCUC pending a final decision on the Company's 2012-2013 RRA. • In November 2011 FortisBC Electric executed an agreement to purchase capacity from the Waneta Expansion. The agreement allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in spring 2015. The form of the agreement was originally accepted for filing by the BCUC in September 2010. The BCUC is conducting its usual review process of the executed agreement, filed in November 2011, to determine whether a hearing is necessary to decide whether the agreement is in the public interest. • In March 2012 the BCUC issued an order establishing a written hearing process to review the prudency of approximately $29 million in capital expenditures incurred related to the Kettle Valley Distribution Source Project, which was substantially completed in 2009. FortisBC Electric believes that the capital expenditures were prudently incurred and, therefore, cannot reasonably determine if any of such expenditures may be disallowed from rate base and any resulting financial impact. The hearing is expected to take place throughout 2012.
FortisAlberta	• In October 2010 the Central Alberta Rural Electrification Association ("CAREA") filed an application with the AUC requesting that, effective January 1, 2012, CAREA be entitled to service any new customers wishing to obtain electricity for use on property overlapping CAREA's service area and that FortisAlberta be restricted to providing service in the CAREA service area only to those customers who are not being provided service by CAREA. FortisAlberta intervened in the proceeding to oppose CAREA's request, with an oral argument heard in April 2012. A decision on this matter is expected during the third quarter of 2012. • In 2010 the AUC initiated a process to reform utility rate regulation for distribution utilities in Alberta. The AUC intends to introduce PBR-based distribution service rates beginning in 2013 for a five-year term, with 2012 to be used as the base year. In July 2011 FortisAlberta, along with other distribution utilities operating under the AUC's jurisdiction, submitted PBR proposals to the AUC. The Company's submission outlines its views as to how PBR should be implemented at FortisAlberta. A hearing on the matter commenced in April 2012 with a decision expected in 2012. • In December 2011 the AUC issued its decision on its 2011 GCOC Proceeding, establishing the allowed ROE at 8.75% for 2011 and 2012 and, on an interim basis, at 8.75% for 2013. The equity component of FortisAlberta's capital structure remains at 41% and will continue at that level until changed by any future order of the AUC. The AUC concluded that it would not return to a formula-based ROE automatic adjustment mechanism at this time and that it would initiate a proceeding in due course to establish a final allowed ROE for 2013 and revisit the matter of a return to a formula-based approach in future periods. • In January 2012 FortisAlberta and other distribution utilities in Alberta filed motions for leave to appeal with the Alberta Court of Appeal with respect to the 2011 GCOC decision, challenging certain pronouncements made by the AUC as being incorrect regarding cost responsibility for stranded assets. In February 2012 FortisAlberta and other utilities filed requests for the AUC to review and vary its pronouncements.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In April 2012 the AUC approved, substantially as filed, an NSA pertaining to FortisAlberta's 2012 distribution revenue requirements resulting in an average increase in customer rates of approximately 5%, effective January 1, 2012, consistent with the interim rate increase that was previously approved by the AUC in December 2011. The increase in customer rates was driven primarily by ongoing investment in energy infrastructure, including increased depreciation and financing costs. The NSA provides for forecast midyear rate base of $2,025 million. The AUC did not approve the continuation of the deferral of volume variances associated with FortisAlberta's Alberta Electric System Operator ("AESO") charges deferral account. This item is to be examined by the AUC in a future proceeding.
Newfoundland Power	• In March 2012 Newfoundland Power filed a Cost of Capital Application with the PUB to discontinue the use of the current ROE automatic adjustment mechanism and to approve a just and reasonable rate of return on average rate base for 2012. A public hearing on the application is currently scheduled for June 2012. • Newfoundland Power expects to file a Rate Stabilization Account ("RSA") application with the PUB by the end of May 2012 to seek an average increase in customer electricity rates of approximately 7%, effective July 1, 2012. The expected increase in rates is primarily due to the result of the normal annual operation of Newfoundland and Labrador Hydro's ("Newfoundland Hydro") Rate Stabilization Plan. Variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to customers through the operation of Newfoundland Power's RSA. The increase in rates, principally due to higher fuel prices, will not have an impact on Newfoundland Power's earnings. • The Company is currently assessing its requirement to file a general rate application with the PUB to recover expected increased costs in 2013.
Maritime Electric	• In February 2012 the PEI Energy Commission (the "PEI Commission") released its Discussion Paper *"Charting Our Electricity Future",* which outlined discussion points the PEI Commission is seeking input on through a consultative process with stakeholders and the general public. These discussion points included: (i) electricity ownership and management on PEI and whether Maritime Electric is doing a good job of balancing safety and reliability with cost of service; (ii) the future role of IRAC, the PEI Energy Corporation and the PEI Office of Energy Efficiency; (iii) a new cable interconnection; (iv) the treatment of the financing of the $47 million of deferred incremental replacement energy costs associated with the Point Lepreau nuclear generating station; (v) regional energy collaboration; (vi) demand-side management; (vii) renewable energy and environmental stewardship; and (viii) potential options for natural gas-generated electricity. Public forums and stakeholder consultations occurred in February and March 2012, in which Maritime Electric was a participant. The PEI Commission is expected to release a final report of its recommendations to the Government of PEI in fall 2012. • In March 2012 Maritime Electric received regulatory approval to defer, for refund to customers in a future period to be determined, contingent income tax expense reductions associated with the Company's amendment of corporate income tax filings for the years 2007 through 2010. The amended filings seek to expense certain costs previously capitalized for income tax purposes. • Maritime Electric intends to file an application with IRAC in fall 2012 for 2013 customer rates and allowed ROE.
FortisOntario	• In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation Incentive Rate Mechanism ("IRM") as prescribed by the OEB. In the first quarter of 2012, the OEB published applicable inflationary and efficiency targets, resulting in minimal changes in base customer electricity distribution rates at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne effective May 1, 2012. The Third-Generation IRM maintains the allowed ROE at 8.01% for 2012. • In April 2012 the OEB issued Final Decisions and Orders for customer rates effective May 1, 2012 at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne. The result was an average 3.1% decrease in residential customer rates in Fort Erie, an average 0.6% increase in residential customer rates in Gananoque, and an average 4.6% decrease in residential customer rates in Port Colborne. The above-noted rate changes were mainly due to changes in rate riders associated with regulatory deferral accounts and smart meter funding. • In April 2011 FortisOntario provided the City of Port Colborne and Port Colborne Hydro with an irrevocable written notice of FortisOntario's election to exercise the purchase option, under the current operating lease agreement, at the purchase option price of approximately $7 million on April 15, 2012. The purchase constitutes the sale of the remaining assets of Port Colborne Hydro to FortisOntario. The purchase transaction was approved by the OEB in March 2012 and closed on April 16, 2012.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• In March 2012 the OEB issued its decision on Algoma Power's Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. The decision approved a price-cap index of 2.81% for customers subject to RRRP funding and 0.38% for those customers not subject to RRRP funding. RRRP funding for 2012 has been set at approximately $11 million. Algoma Power's allowed ROE is maintained at 9.85% for 2012. • FortisOntario expects to file a COS Application in 2012 for harmonized electricity distribution rates in Fort Erie, Port Colborne and Gananoque, effective January 1, 2013, using a 2013 forward test year. The timing of the filing of the COS Application corresponds with the ending of the period that the current Third-Generation IRM applies to FortisOntario.
Caribbean Utilities	• In April 2012 the ERA approved Caribbean Utilities' 2012-2016 Capital Investment Plan ("CIP") for US$122 million of non-generation installation capital expenditures. The remaining US$62 million of the 2012-2016 CIP relates to new generation installation, which would be subject to a competitive solicitation process with the next generation unit scheduled for installation in 2014. The 2012-2016 CIP was prepared in line with the Certificate of Need that was filed with the ERA in November 2011, which included 18 MW of generating capacity to be installed in either 2015 or 2016, contingent on load growth over the next two years. • In March 2012 the ERA approved the creation of Caribbean Utilities' wholly owned subsidiary DataLink, Ltd. ("DataLink"). Subsequently, the Information and Communications Technology Authority ("ICTA") granted a licence to DataLink to provide fibre optic infrastructure on Grand Cayman. The ICTA licence allows DataLink to assume full responsibility for existing pole attachment agreements and optical fibre lease agreement currently held by Caribbean Utilities with third-party information and communications technology service providers. • In December 2011 Caribbean Utilities conducted and completed a competitive bidding process to fill up to 13 MW of non-firm renewable energy capacity. Two renewable energy developers have been chosen to commence discussions with Caribbean Utilities to provide energy to the utility's grid. The proposals being considered are two 5-MW solar photovoltaic power plants and one 3-MW small-scale wind turbine project. Caribbean Utilities and the developers are expected to commence negotiations related to power purchase agreements. The power purchase agreements, however, are subject to ERA review and approval.
Fortis Turks and Caicos	• An independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands was performed during the third quarter of 2011 on behalf of the Interim Government. The purpose of the review was to: (i) assess the effectiveness of the current regulatory framework in terms of its administrative and economic efficiency; (ii) assess the current and proposed electricity costs and tariffs in the Turks and Caicos Islands in relation to comparable regional and international utilities; (iii) make recommendations for a revised regulatory framework and *Electricity Ordinance*; and (iv) make recommendations for the implementation and operation of the revised regulatory framework. Fortis Turks and Caicos provided a comprehensive response to the Interim Government in January 2012 stating that the Company supports limited mutually agreed upon reforms, but that its current licences must be respected and can only be changed by mutual consent. Specifically, Fortis Turks and Caicos would support reforms that strengthen the role of the regulator in the rate-setting process and that are fair to all stakeholders. Negotiations between Fortis Turks and Caicos and the Interim Government are expected to commence mid-2012 with implementation of any resulting changes in the regulatory framework expected to occur at the end of 2012. • In February 2012 the Interim Government approved an approximate 26% increase in electricity rates, effective April 1, 2012, for Fortis Turks and Caicos' large hotel customers. In addition, other qualitative enhancements to the franchise were also achieved, including: (i) improved wording in the Electricity Rate Regulation; (ii) an approved increase in kilowatt hour consumption thresholds for both medium and large hotels; (iii) an expansion of service territory to cover all of the Caicos Islands, except for areas currently serviced by private suppliers' licences, with new 25-year licenses issued for the expanded service territory; and (iv) the discontinuance of the government subsidization of the utility's South Caicos operations. • In March 2012 Fortis Turks and Caicos submitted its 2011 annual regulatory filing outlining the Company's performance in 2011. Included in the filing were the calculations, in accordance with the utility's licence, of rate base of US$166 million for 2011 and cumulative shortfall in achieving allowable profits of US$72 million as at December 31, 2011. • In April 2012 Fortis Turks and Caicos entered into a Streetlight Takeover Agreement with the Interim Government whereby the responsibility for the ownership, installation and maintenance of all streetlights in the utility's service territory was transferred to Fortis Turks and Caicos.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between March 31, 2012 and December 31, 2011.

Significant Changes in the Consolidated Balance Sheets (Unaudited) between March 31, 2012 and December 31, 2011

Balance Sheet Account	Increase / (Decrease) *($ millions)*	Explanation
Accounts receivable	58	The increase was primarily due to the impact of a seasonal increase in sales, and the operation of the equal payment plans for customers, mainly at the FortisBC Energy companies and Newfoundland Power.
Inventories	(58)	The decrease was driven by the normal seasonal reduction of gas in storage at the FortisBC Energy companies, due to higher consumption during the winter months.
Utility capital assets	96	The increase primarily related to $211 million invested in electricity and gas systems, partially offset by depreciation and customer contributions for the three months ended March 31, 2012.
Short-term borrowings	(83)	The decrease was driven by lower borrowings at the FortisBC Energy companies due to seasonality of operations.
Regulatory liabilities – current and long-term	70	The increase was driven by deferrals at the FortisBC Energy companies associated with an increase in the Rate Stabilization Deferral Account at FEVI, reflecting amounts collected in customer rates in excess of the cost of providing service during the three months ended March 31, 2012, and an increase in the Midstream Cost Reconciliation Account, as amounts collected in customer rates were in excess of actual midstream gas-delivery costs for the three months ended March 31, 2012.
Shareholders' equity (before non-controlling interests)	78	The increase was primarily due to net earnings attributable to common equity shareholders for the three months ended March 31, 2012, less common share dividends, and the issuance of common shares under the Corporation's dividend reinvestment plan.
Non-controlling interests	38	The increase was driven by advances from the 49% non-controlling interests in the Waneta Expansion Limited Partnership ("Waneta Partnership") and an approximate $12 million, or 15%, equity investment by two First Nations bands in the LNG storage facility on Vancouver Island.

LIQUIDITY AND CAPITAL RESOURCES

The table below outlines the Corporation's consolidated sources and uses of cash for the three months ended March 31, 2012, as compared to the same period in 2011, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows (Unaudited)	**Quarter Ended March 31**		
($ millions)	**2012**	2011	Variance
Cash, Beginning of Period	**87**	107	(20)
Cash Provided by (Used in):			
Operating Activities	**328**	302	26
Investing Activities	**(211)**	(217)	6
Financing Activities	**(94)**	(108)	14
Cash, End of Period	**110**	84	26

Operating Activities: Cash flow from operating activities, after working capital adjustments, was $26 million higher quarter over quarter largely due to favourable changes in working capital mainly associated with current regulatory deferral accounts at the FortisBC Energy companies and FortisAlberta, and higher earnings. The above-noted increases were partially offset by unfavourable changes in accounts receivable, inventories and long-term regulatory deferral accounts.

Investing Activities: Cash used in investing activities was comparable quarter over quarter. Lower capital spending at the regulated utilities in western Canada and the Caribbean was largely offset by an increase in capital spending related to the non-regulated Waneta Expansion.

Financing Activities: Cash used in financing activities was $14 million lower for the quarter compared to the same quarter last year. The decrease was due to higher advances from non-controlling interests and lower repayments of short-term borrowings, partially offset by: (i) higher common share dividends; (ii) lower proceeds from the issuance of common shares; and (iii) lower net borrowings under committed credit facilities classified as long term.

Net repayment of short-term borrowings was $83 million for the quarter compared to $98 million for the same quarter last year. The change quarter over quarter was driven by the FortisBC Energy companies.

Net borrowings under committed credit facilities for the first quarter of 2012 compared to the same quarter of 2011 are summarized in the following table.

Net (Repayments) Borrowings Under Committed Credit Facilities (Unaudited)			
	Quarter Ended March 31		
($ millions)	**2012**	2011	Variance
FortisAlberta	**(29)**	12	(41)
FortisBC Electric	**(9)**	-	(9)
Newfoundland Power	**14**	13	1
Corporate	**31**	(10)	41
Total	**7**	15	(8)

Borrowings under credit facilities by the utilities are primarily in support of their capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

Advances of approximately $29 million were received in the first quarter of 2012 from non-controlling interests in the Waneta Partnership to finance capital spending related to the Waneta Expansion compared to $17 million received in the first quarter of 2011. In January 2012 advances of approximately $12 million were received from two First Nations bands representing their 15% equity investment in the LNG storage facility on Vancouver Island.

Proceeds from the issuance of common shares decreased $9 million quarter over quarter, reflecting a lower number of stock options exercised under the Corporation's stock option plans.

Common share dividends paid during the first quarter of 2012 were $44 million, net of $13 million in dividends reinvested, compared to $35 million, net of $16 million in dividends reinvested, paid during the same quarter of 2011. The dividend paid per common share for the first quarter of 2012 was $0.30 compared to $0.29 for the first quarter of 2011. The weighted average number of common shares outstanding for the first quarter was 189.0 million compared to 175.0 million for the first quarter of 2011.

CONTRACTUAL OBLIGATIONS

As at March 31, 2012, consolidated contractual obligations of Fortis over the next five years and for periods thereafter are outlined in the following table. A detailed description of the nature of the obligations is provided in the 2011 Annual MD&A and below, where applicable. The presentation of certain contractual obligations has changed from that provided in the 2011 Annual MD&A due to the adoption of US GAAP. For further information concerning these changes, refer to the 2011 audited consolidated financial statements prepared in accordance with US GAAP and voluntarily filed on SEDAR.

Contractual Obligations (Unaudited) **As at March 31, 2012** *($ millions)*	**Total**	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Long-term debt	**5,901**	121	768	428	4,584
Capital lease obligations [(1)]	**2,501**	42	86	89	2,284
Waneta Partnership promissory note	**72**	-	-	-	72
Gas purchase contract obligations [(2)]	**217**	130	87	-	-
Power purchase obligations					
FortisBC Electric	**25**	12	10	3	-
FortisOntario	**399**	41	99	103	156
Maritime Electric	**176**	42	79	41	14
Capital cost	**457**	17	36	36	368
Joint-use asset and share service agreements	**64**	4	8	7	45
Operating lease obligations	**155**	20	36	34	65
Defined benefit pension funding contributions [(3)]	**111**	40	46	22	3
Other	**8**	1	2	1	4
Total	**10,086**	470	1,257	764	7,595

(1) Includes principal payments and approximately $2 million of imputed interest and executory costs, mainly related to FortisBC Electric's Brilliant Power Purchase Agreement and Brilliant Terminal Station.

(2) Based on index prices as at March 31, 2012

(3) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2012	FortisBC Energy companies (covering non-unionized employees)
December 31, 2013	FortisBC Energy companies (covering unionized employees)
December 31, 2013	FortisBC Electric
December 31, 2014	Newfoundland Power

The estimate of defined benefit pension funding contributions in the above table includes the impact of the outcome of the December 31, 2011 actuarial valuation, completed in April 2012, associated with the defined benefit pension plan at Newfoundland Power. As a result of the valuation, Newfoundland Power is required to fund a solvency deficiency of approximately $53.5 million, including interest, over five years beginning in 2012, which is included in the above table.

Other contractual obligations, which are not reflected in the above table, did not materially change from those disclosed in the 2011 Annual MD&A, except as described below.

In January 2012 two First Nations bands each invested approximately $6 million in equity in the Mount Hayes LNG storage facility, representing a 15% equity interest in the Mount Hayes Limited Partnership, with FEVI holding the controlling 85% ownership interest. The non-controlling interests hold put options, which, if exercised, would require FEVI to repurchase the 15% ownership interest for cash, in accordance with the terms of the partnership agreement.

For a discussion of the nature and amount of the Corporation's consolidated capital expenditure program, which is not included in the Contractual Obligations table above, refer to the "Capital Expenditure Program" section of this MD&A.

CAPITAL STRUCTURE

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure (Unaudited)	**As at**			
	March 31, 2012		December 31, 2011	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [(1)] [(2)]	**6,186**	**56.2**	6,296	57.1
Preference shares	**912**	**8.3**	912	8.3
Common shareholders' equity	**3,901**	**35.5**	3,823	34.6
Total [(3)]	**10,999**	**100.0**	11,031	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash
(2) Excluding capital lease obligations and financing obligations under lease-in lease-out transactions, the debt component of the capital structure was 54.4% as at March 31, 2012 and 55.3% as at December 31, 2011.
(3) Excludes amounts related to non-controlling interests

The improvement in the capital structure was primarily due to: (i) lower short-term borrowings; (ii) net earnings attributable to common equity shareholders, net of dividends; (iii) an increase in cash; and (iv) common shares issued under the Corporation's dividend reinvestment plan.

CREDIT RATINGS

The Corporation's credit ratings are as follows:

Standard & Poor's	A-/Credit Watch - Negative (unsecured debt credit rating)
DBRS	A(low)/Under Review - Developing Implications (unsecured debt credit rating)

The above credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis. In February 2012, after the announcement by Fortis that it had entered into an agreement to acquire CH Energy Group, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P placed the Corporation's credit rating on credit watch with negative implications.

CAPITAL EXPENDITURE PROGRAM

Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred.

A breakdown of the $229 million in gross capital expenditures by segment for the first quarter of 2012 is provided in the following table.

Gross Consolidated Capital Expenditures (Unaudited) [(1)]
Quarter Ended March 31, 2012
($ millions)

FortisBC Energy Companies	Fortis Alberta [(2)]	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities - Canadian	**Total Regulated Utilities - Canadian**	**Regulated Electric Utilities - Caribbean**	**Non-Regulated - Utility** [(3)]	**Fortis Properties**	**Total**
46	79	17	15	9	**166**	**10**	**48**	**5**	**229**

(1) Relates to cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected in the consolidated statement of cash flows. Includes non-ARO removal expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2012. Excludes capitalized amortization and non-cash equity component of AFUDC.
(2) Includes payments made to AESO for investment in transmission-related capital projects
(3) Includes non-regulated generation capital expenditures, mainly related to the Waneta Expansion

Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

There have been no material changes in the overall expected level, nature and timing of the Corporation's significant capital projects from those that were disclosed in the 2011 Annual MD&A. Gross consolidated capital expenditures for 2012 are forecasted at approximately $1.3 billion.

FEI's Customer Care Enhancement Project, at an estimated total project cost of $110 million, came into service in January 2012. Approximately $25 million of the project costs were incurred in the first quarter of 2012, mainly related to final contractor payments, with a remaining $5 million expected to be incurred in the second quarter of 2012.

Construction progress on the $900 million Waneta Expansion is going well and the project is currently on schedule. Major construction activities on-site include the completion of the excavation of the intake, powerhouse and power tunnels. Approximately $290 million has been spent on the Waneta Expansion since construction began late in 2010.

Over the five-year period 2012 through 2016, consolidated gross capital expenditures are expected to be approximately $5.5 billion, consistent with that disclosed in the 2011 Annual MD&A. Approximately 64% of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC Electric. Approximately 23% and 13% of the capital spending is expected to be incurred at the regulated gas utilities and non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, 39% of utility capital spending is expected to be incurred to meet customer growth; 38% is expected to be incurred to ensure continued and enhanced performance, reliability and safety of generation and T&D assets (i.e., sustaining capital expenditures); and 23% is expected to be incurred for facilities, equipment, vehicles, information technology and other assets.

CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flow available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt offerings.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis. Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends.

As at March 31, 2012, management expects consolidated long-term debt maturities and repayments to average approximately $265 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As the hydroelectric assets and water rights of the Exploits River Hydro Partnership ("Exploits Partnership") had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $56 million as at March 31, 2012 (December 31, 2011 - $56 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. For further information refer to Note 35 to the Corporation's 2011 annual audited consolidated financial statements prepared in accordance with US GAAP.

Except for the debt at the Exploits Partnership, as discussed above, Fortis and its subsidiaries were in compliance with debt covenants as at March 31, 2012 and are expected to remain compliant throughout the remainder of 2012.

CREDIT FACILITIES

As at March 31, 2012, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which $2.0 billion was unused, including $769 million unused under the Corporation's $800 million committed revolving credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.0 billion of the total credit facilities are committed facilities with maturities ranging from 2013 through 2017.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities (Unaudited)				**As at**	
($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**March 31, 2012**	December 31, 2011
Total credit facilities	845	1,389	13	**2,247**	2,248
Credit facilities utilized:					
Short-term borrowings	-	(73)	(3)	**(76)**	(159)
Long-term debt (including current portion)	(31)	(50)	-	**(81)**	(74)
Letters of credit outstanding	(1)	(65)	-	**(66)**	(66)
Credit facilities unused	813	1,201	10	**2,024**	1,949

As at March 31, 2012 and December 31, 2011, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In March 2012 Newfoundland Power renegotiated and amended its $100 million unsecured committed credit facility, obtaining an extension to the maturity of the facility to August 2017 from August 2015. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In April 2012 FortisBC Electric renegotiated and amended its credit facility agreement resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2015 and $50 million now maturing in May 2013.

Fortis has requested an increase in the amount available for borrowing under its committed corporate credit facility from $800 million to $1 billion, as permitted under the credit facility agreement, and expects the increase to be available in May 2012.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments (Unaudited)	**As at**			
	March 31, 2012		December 31, 2011	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**45**	**50**	45	49
Long-term debt, including current portion	**5,901**	**7,207**	5,912	7,296

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The financial instruments table above excludes the long-term other asset associated with the Corporation's previous investment in Belize Electricity. The fair value of the Corporation's expropriated investment in Belize Electricity determined under the Government of Belize's valuation is significantly lower than the fair value determined under the Corporation's independent valuation of the utility. Due to uncertainty in the ultimate amount and ability of the Government of Belize to pay compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the long-term other asset at the carrying value of the Corporation's previous investment in Belize Electricity, including foreign exchange impacts, which was approximately $104 million as at March 31, 2012.

Risk Management: The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy Corporation and BECOL is the US dollar. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar.

As at March 31, 2012, the Corporation's corporately issued US$550 million (December 31, 2011 – US$550 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at March 31, 2012, the Corporation had approximately US$8 million (December 31, 2011 - US$6 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as effective hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. As a result, the Corporation recognized a foreign exchange loss of approximately $1.5 million in earnings during the first quarter of 2012.

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas prices through the use of derivative financial instruments. The Corporation and its subsidiaries do not hold or issue derivative financial instruments for trading purposes. As at March 31, 2012, the Corporation's derivative contracts consisted of a foreign exchange forward contract, natural gas swap and option contracts, and gas purchase contract premiums, all held by the FortisBC Energy companies.

The following table summarizes the Corporation's derivative financial instruments.

Derivative Financial Instruments (Unaudited)				**As at**	
				March 31, 2012	December 31, 2011
(Liability) Asset	**Maturity**	**Number of Contracts**	**Volume *(petajoules)***	**Carrying Value [1] *($ millions)***	Carrying Value [1] *($ millions)*
Foreign exchange forward contract	**2012**	**1**	**-**	**-**	-
Fuel option contracts	**2012**	**-**	**-**	**-**	(1)
Natural gas derivatives:					
Swaps and options	**2014**	**90**	**51**	**(135)**	(135)
Gas purchase contract premiums	**2014**	**27**	**99**	**3**	-

[1] Carrying value approximates fair value. The (liability) asset represents the gross derivatives balance.

The foreign exchange forward contract is held by FEI to hedge the cash flow risk related to approximately US$4 million remaining to be paid under a contract for the implementation of a customer information system.

The fuel option contracts were held by Caribbean Utilities to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. The fuel option contracts matured in March 2012.

The natural gas derivatives are held by the FortisBC Energy companies and are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, to temper gas price volatility on customer rates and to reduce the risk of regional price discrepancies. As directed by the BCUC, FEI and FEVI suspended their commodity hedging activities in 2011, which has continued into 2012, with the exception of certain limited swaps. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged.

The changes in the fair values of the foreign exchange forward contract and natural gas derivatives are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the derivative financial instruments were recorded in accounts payable as at March 31, 2012 and as at December 31, 2011.

The fair value of the foreign exchange forward contract is calculated using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas. The fair values of the foreign exchange forward contract and natural gas derivatives are estimates of the amounts that would have to be received or paid to terminate the outstanding contracts as at the balance sheet dates.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $66 million, as at March 31, 2012, the Corporation had no off-balance sheet arrangements, such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities, that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

There were no changes in the Corporation's significant business risks during the first quarter of 2012 from those disclosed in the 2011 Annual MD&A, except for those described below.

Regulatory Risk: In April 2012 regulatory decisions received for 2012 and 2013 customer gas delivery rates at the FortisBC Energy companies and for 2012 customer electricity distribution rates at FortisAlberta help to reduce regulatory risk at the utilities. For further information, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Completion of the Acquisition of CH Energy Group: There is risk that some, or all, of the expected benefits of the acquisition of CH Energy Group may fail to materialize or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be impacted by a number of factors, many of which are beyond the control of Fortis.

Capital Resources and Liquidity Risk - Credit Ratings: In February 2012, after the announcement by Fortis that it had entered into an agreement to acquire all of the shares of CH Energy Group, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P placed the Corporation's credit rating on credit watch with negative implications. FortisAlberta's existing debt credit rating by S&P was confirmed in January 2012, but was put on credit watch with negative implications in February 2012 as a result of the Corporation's credit rating being placed on credit watch. During the first quarter of 2012, DBRS confirmed FortisAlberta and Newfoundland Power's existing debt credit ratings, and both DBRS and S&P confirmed Caribbean Utilities' debt credit ratings.

Defined Benefit Pension Plan Assets: As at March 31, 2012, the fair value of the Corporation's consolidated defined benefit pension plan assets was $821 million, up $36 million or 4.6%, from $785 million as at December 31, 2011.

Labour Relations: The collective agreement between FortisBC Electric and the Canadian Office and Professional Employees Union ("COPE"), Local 378, expired January 31, 2011. An agreement expiring in March 2014 has been reached with regard to certain customer service employees. Discussions continue with regard to the remaining FortisBC Electric COPE bargaining unit.

The collective agreements between the FortisBC Energy companies and the International Brotherhood of Electrical Workers ("IBEW"), Local 213, expired on March 31, 2011. IBEW, Local 213, represents employees in specified occupations in the areas of T&D. The parties are negotiating terms of a renewed collective agreement.

The collective agreements between the FortisBC Energy companies and COPE, Local 378, expired on March 31, 2012. COPE, Local 378, represents employees in specified occupations in the areas of administration and operations support. The parties are negotiating the terms of a renewed collective agreement.

The two collective agreements between Newfoundland Power and IBEW, Local 1620, expired on September 30, 2011. During the first quarter of 2012, one of the two newly negotiated collective agreements was ratified. The other collective agreement was not accepted and is now subject to ratification in May 2012. The agreements are for three-year terms expiring in September 2014.

CHANGES IN ACCOUNTING POLICIES

Transition to US GAAP: Effective January 1, 2012, Fortis retroactively adopted US GAAP with the restatement of comparative reporting periods. The areas of most significant financial statement impacts upon adopting US GAAP include, but are not limited to the: (i) recognition of the funded status of defined benefit pension plans on the consolidated balance sheet and the inability to recognize regulatory assets or liabilities associated with other post-employment benefit ("OPEB") costs that are recovered on a cash basis; (ii) recognition of the Brilliant Power Purchase Agreement as a capital lease at FortisBC Electric; (iii) recognition of lease-in lease-out transactions at the FortisBC Energy companies as financing transactions with the corresponding assets recognized as utility capital assets and the sales proceeds accounted for as long-term debt; (iv) reclassification of preference shares from long-term liabilities to shareholders' equity; and (v) the calculation and recognition of income taxes based on enacted versus substantially enacted income tax rates.

The above-noted items do not represent a complete list of differences between US GAAP and Canadian GAAP. Other less significant differences have also been identified and accounted for. A detailed description of the differences and a detailed reconciliation between the Corporation's annual audited consolidated Canadian GAAP and annual audited consolidated US GAAP financial statements for 2011 is disclosed in Note 38 to the Corporation's voluntarily filed annual audited consolidated US GAAP financial statements with accompanying notes thereto for the year ended December 31, 2011, with 2010 comparatives. A detailed reconciliation between the Corporation's interim unaudited consolidated 2011 Canadian GAAP and interim unaudited consolidated 2011 US GAAP financial statements is provided in the above-noted voluntarily filed document under the section "Supplemental Interim Consolidated Financial Statements for the Year Ended December 31, 2011 (Unaudited)".

The audited quantification and reconciliation of the Corporation's consolidated balance sheet as at December 31, 2011, prepared in accordance with US GAAP versus Canadian GAAP, may be summarized as follows.

- Total assets as at December 31, 2011 increased by approximately $603 million. The increase was due primarily to increases in regulatory assets and utility capital assets in accordance with US GAAP.

- Total liabilities as at December 31, 2011 increased by approximately $337 million. The increase was due primarily to increases in long-term debt, capital lease obligations and pension liabilities in accordance with US GAAP, partially offset by the reclassification of preference shares from liabilities to shareholders' equity.

- Shareholders' equity as at December 31, 2011 increased by approximately $266 million. The increase was due primarily to the reclassification of preference shares from liabilities to shareholders' equity in accordance with US GAAP, partially offset by a reduction in retained earnings of approximately $37 million and an increase in accumulated other comprehensive loss of approximately $21 million. Approximately half of the reduction in retained earnings resulted from higher income taxes and is expected to reverse in a future period once pending Canadian federal income tax legislation is passed and proposed Part VI.1 tax rate changes are enacted.

There were no material adjustments to the Corporation's consolidated 2011 earnings under US GAAP due to the Corporation's continued ability to apply rate-regulated accounting policies.

The unaudited quantification and reconciliation of the Corporation's consolidated statement of earnings for the three months ended March 31, 2011, prepared in accordance with US GAAP versus Canadian GAAP, may be summarized as follows:

- *Three Months Ended March 31, 2011 (Unaudited):* Consolidated net earnings recognized in accordance with US GAAP increased by $3 million, from $125 million to $128 million. The increase was due primarily to the reclassification of preference share dividends totaling $4 million, in accordance with US GAAP, from finance charges to earnings attributable to preference equity shareholders, partially offset by a reduction in earnings attributable to common equity shareholders of approximately of $1 million.

Changes in Accounting Policies: Effective January 1, 2012, the FortisBC Energy companies prospectively adopted the policy of accruing for non-ARO removal costs in depreciation expense, as requested in their 2012-2013 RRAs and subsequently approved by the BCUC in its April 2012 rate decision. The accrual of estimated non-ARO removal costs is included in depreciation expense and the provision balance is recognized as a long-term regulatory liability. Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. Non-ARO removal costs are direct costs incurred by the FortisBC Energy companies in taking assets out of service, whether through actual removal of the assets or through disconnection of the assets from the transmission or distribution system. Prior to 2012 non-ARO removal costs, net of salvage proceeds, were recognized in operating expenses as incurred with variances between actual non-ARO removal costs and those forecast for rate-setting purposes recorded in a regulatory deferral account for future recovery from, or refund to, customers in rates commencing in 2012. During the first quarter of 2012, $4 million of non-ARO removal costs were accrued as a part of depreciation expense. During the first quarter of 2011, $3 million of non-ARO removal costs were recognized in operating expenses.

Prior to 2012 variances from forecast, adjusted for certain revenue and cost variances which flowed through to customers, for rate-setting purposes were shared equally between customers and FortisBC Electric. Prospectively from January 1, 2012, the above sharing of positive or negative variances is no longer in effect pursuant to the utility's filed 2012-2013 RRA, which is subject to BCUC approval and reflects a COS rate-setting methodology. Beginning in 2012 variances from forecast for rate-setting purposes related to electricity revenue, purchased power costs and certain other costs, are subject to full deferral account treatment, to be recovered from, or refunded to, customers in future rates and, therefore, are not subject to the sharing mechanism that existed prior to 2012 and do not impact earnings in 2012.

New US GAAP Accounting Pronouncements: The following new US GAAP accounting pronouncements that are applicable to, and were adopted by, Fortis effective January 1, 2012 are described as follows:

Presentation of Comprehensive Income
The Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 220, *Comprehensive Income.* The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. Fortis continues to report the components of comprehensive income in a separate but consecutive statement.

Testing Goodwill for Impairment
The Corporation has prospectively adopted the amendments to ASC Topic 350, *Goodwill.* The amended standard allows entities testing goodwill for impairment to have the option of performing a qualitative assessment before calculating the fair value of the reporting unit. If the qualitative factors indicate that the fair value of the reporting unit is more likely than not (greater than a 50% chance) to be greater than the carrying value, then the two-step impairment test, including the quantification of the fair value of the reporting unit, would not be required. In adopting the amendments, Fortis will

perform a qualitative assessment before calculating the fair value of its reporting units when it performs its annual impairment test on October 1.

Fair Value Measurement
The Corporation adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amended standard improves comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with US GAAP. The amendment does not change what items are measured at fair value but instead makes various changes to the guidance pertaining to how fair value is measured. The above-noted changes did not materially impact the Corporation's consolidated financial statements for the three months ended March 31, 2012.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's interim unaudited consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known.

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates during the first quarter of 2012 from those disclosed in the 2011 Annual MD&A.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Fortis
Following the announcement of the proposed acquisition of CH Energy Group on February 21, 2012, several complaints, which named Fortis and other defendants, were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, challenging the proposed acquisition. The complaints generally allege that the directors of CH Energy Group breached their fiduciary duties in connection with the proposed transaction and that CH Energy Group, Fortis, FortisUS Inc., and Cascade Acquisition Sub Inc. aided and abetted that breach.

The outcome of these lawsuits is uncertain and cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements. An adverse judgment for monetary damages could have a material adverse effect on the operations of the surviving company after the completion of the acquisition. A preliminary injunction could delay or jeopardize the completion of the acquisition and an adverse judgment granting permanent injunctive relief could indefinitely enjoin completion of the transaction. Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of such lawsuits is not expected to have a material adverse effect on the consolidated financial condition of Fortis. The defendants intend to vigorously defend themselves against the lawsuits.

FHI
During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The

exposure has been fully provided for in the consolidated financial statements. FHI has begun the appeal process associated with the assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric
The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric, dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements. A date for mediation of this matter has been set for December 2012.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended June 30, 2010 through March 31, 2012. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements, which have been prepared in accordance with US GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected using US GAAP for non-regulated entities. The nature of regulation is further disclosed in Notes 2, 3 and 7 to the Corporation's 2011 annual audited consolidated financial statements prepared in accordance with US GAAP. The quarterly financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results (Unaudited)		**Net Earnings Attributable to Common Equity**	**Earnings per Common Share**	
Quarter Ended	**Revenue** *($ millions)*	**Shareholders** *($ millions)*	**Basic** *($)*	**Diluted** *($)*
March 31, 2012	1,149	121	0.64	0.62
December 31, 2011	1,034	82	0.44	0.43
September 30, 2011	699	56	0.30	0.30
June 30, 2011	846	57	0.32	0.32
March 31, 2011	1,159	116	0.66	0.64
December 31, 2010	1,032	127	0.73	0.71
September 30, 2010	717	43	0.25	0.25
June 30, 2010	831	53	0.31	0.31

A summary of the past eight quarters reflects the Corporation's continued organic growth, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Fortis subsidiaries, seasonality may vary. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Earnings for the third quarter ended September 30, 2011 included the $11 million after-tax termination fee paid to Fortis by Central Vermont Public Service Corporation ("CVPS"). Financial results from the fourth quarter ended

December 31, 2011 reflected the acquisition of the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011. Financial results from June 20, 2011 reflected the discontinuance of the consolidation method of accounting for Belize Electricity due to the expropriation of the utility by the GOB. For further information, refer to the "Key Trends and Risks – Expropriated Assets" and "Business Risk Management – Investment in Belize" sections of the 2011 Annual MD&A. Revenue for the third quarter ended September 30, 2010 reflected the favourable cumulative retroactive impact associated with the 2010 revenue requirements decision at FortisAlberta.

March 2012 / March 2011: Net earnings attributable to common equity shareholders were $121 million, or $0.64 per common share, for the first quarter of 2012 compared to earnings of $116 million, or $0.66 per common share, for the first quarter of 2011. A discussion of the quarter over quarter variance in financial results is provided in the "Financial Highlights" section of this MD&A.

December 2011 / December 2010: Net earnings attributable to common equity shareholders were $82 million, or $0.44 per common share, for the fourth quarter of 2011 compared to earnings of $127 million, or $0.73 per common share, for the fourth quarter of 2010. Excluding the one-time $46 million favourable impact to Newfoundland Power's earnings in the fourth quarter of 2010 due to the rerecognition of a regulatory asset, as required under US GAAP, to recognize amounts recoverable from customers upon regulatory approval of the adoption the accrual method of accounting for OPEB costs, earnings increased $1 million quarter over quarter. The increase in earnings was led by the FortisBC Energy Companies, driven by rate base growth, lower-than-expected corporate income taxes and finance charges in 2011, and higher gas transportation volumes to the forestry and mining sectors, partially offset by both lower customer additions and capitalized AFUDC. The above increase in earnings was partially offset by a decrease in earnings at Newfoundland Power, Other Canadian Regulated Electric Utilities, Fortis Turks and Caicos and Fortis Properties. The decrease in earnings at Newfoundland Power reflected a lower allowed ROE and higher operating expenses, partially offset by reduced energy supply costs in the fourth quarter of 2011. Lower earnings at Other Canadian Regulated Electric Utilities were due to decreased electricity sales and higher operating expenses. Lower earnings at Fortis Turks and Caicos were due to higher depreciation and operating expenses, partially offset by reduced energy supply costs in 2011 reflecting the use of new, more fuel-efficient generating units. Earnings at Fortis Properties during the fourth quarter of 2010 reflected lower corporate income tax rates, which reduced deferred taxes in that period. An 8% increase in the weighted average number of common shares outstanding quarter over quarter, largely associated with the public common equity offering in mid-2011, had the impact of tempering earnings per common share.

September 2011 / September 2010: Net earnings attributable to common equity shareholders were $56 million, or $0.30 per common share, for the third quarter of 2011 compared to earnings of $43 million, or $0.25 per common share, for the third quarter of 2010. The increase in earnings was mainly due to the $11 million after-tax fee paid to Fortis in July 2011, following the termination of the Merger Agreement between Fortis and CVPS. Results also improved due to rate base growth associated with energy infrastructure investment, mainly at the regulated utilities in western Canada, a net foreign exchange gain of approximately $2.5 million after tax associated with the previously hedged investment in Belize Electricity, lower-than-expected operating costs at the FortisBC Energy companies due to the timing of spending and capitalization of certain operating expenses in 2011 and a higher allowed ROE at Algoma Power. The above increases in earnings were partially offset by the impact of the regulator-approved reversal in the third quarter of 2010 of $4 million after tax of project overrun costs previously expensed in 2009 related to the conversion of Whistler customer appliances from propane to natural gas, the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility since June 2011, lower capitalized AFUDC at FortisBC Electric, lower non-regulated hydroelectric production in Belize and the timing of recording the 2010 revenue requirements decision at FortisAlberta. The favourable cumulative impact of the decision was recorded in the third quarter of 2010 when the decision was received. A 4% increase in the weighted average number of common shares outstanding quarter over quarter, largely associated with the public common equity offering in mid-2011, had the impact of tempering earnings per common share.

June 2011 / June 2010: Net earnings attributable to common equity shareholders were $57 million, or $0.32 per common share, for the second quarter of 2011 compared to earnings of $53 million, or $0.31 per common share, for the second quarter of 2010. The increase was mainly due to improved performance at Canadian Regulated Electric Utilities, driven by rate base growth associated with energy infrastructure investment, mainly at the electric utilities in western Canada; return earned on additional investment in automated meters at FortisAlberta, as approved by the regulator; lower market-priced purchased power costs at FortisBC Electric and a higher allowed ROE at Algoma Power. Results also improved due to lower corporate business development costs. The above increases in earnings were partially offset by the unfavourable impact of the timing of spending of certain regulator-approved increased operating expenses at the FortisBC Energy companies during 2011, lower non-regulated hydroelectric generation in Belize, and lower contribution from Fortis Properties reflecting lower occupancies at hotel operations in western Canada and increased operating expenses. During the second quarter of 2011, the Government of Belize expropriated the Corporation's investment in Belize Electricity.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

In an effort to optimize customer service operations within the FortisBC Energy companies, a Customer Care Enhancement Project was implemented in January 2012 with new in-house customer contact and billing centres replacing the services of an external third-party service provider. This represents a material change in the Corporation's internal controls over financial reporting surrounding the revenue, receivable and receipts cycle. Throughout the related systems design and implementation, management had considered the control risks associated with the systems changes and had performed procedures to obtain reasonable assurance on the design of all new and significantly modified internal controls over financial reporting as a result of the project. It has been concluded that during the first quarter 2012, other than the above-noted change, there was no change in the Corporation's internal controls over financial reporting that has materially, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

OUTLOOK

The Corporation's significant capital expenditure program, which is expected to be approximately $5.5 billion over the five-year period 2012 through 2016, should support continuing growth in earnings and dividends.

The pending acquisition of CH Energy Group is expected to close by the end of the first quarter of 2013. Fortis remains disciplined and patient in its pursuit of additional electric and gas utility acquisitions in the United States and Canada that will add value for Fortis shareholders. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

OUTSTANDING SHARE DATA

As at May 1, 2012, the Corporation had issued and outstanding approximately 189.3 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; and 10.0 million First Preference Shares, Series H. Only the common shares of the Corporation have voting rights.

The number of common shares of Fortis that would be issued if all outstanding stock options and First Preference Shares, Series C and E were converted as at May 1, 2012 is as follows.

Conversion of Securities into Common Shares (Unaudited)
As at May 1, 2012

Security	**Number of Common Shares** *(millions)*
Stock Options	**4.6**
First Preference Shares, Series C	**3.8**
First Preference Shares, Series E	**6.2**
Total	**14.6**

Additional information, including the Fortis 2011 Annual Information Form, Management Information Circular and Annual Report, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

FORTIS INC.

Interim Consolidated Financial Statements
For the three months ended March 31, 2012 and 2011
(Unaudited)

Prepared in accordance with accounting principles generally accepted in the United States

Fortis Inc.
Consolidated Balance Sheets (Unaudited)
As at
(in millions of Canadian dollars)

	March 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	**$ 110**	$ 87
Accounts receivable	**696**	638
Prepaid expenses	**17**	19
Inventories	**76**	134
Regulatory assets (Note 3)	**168**	219
Deferred income taxes	**33**	24
	1,100	1,121
Other assets	**194**	184
Regulatory assets (Note 3)	**1,451**	1,400
Deferred income taxes	**3**	8
Utility capital assets	**9,064**	8,968
Income producing properties	**595**	594
Intangible assets	**324**	325
Goodwill	**1,563**	1,565
	$ 14,294	$ 14,165
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 16)	**$ 76**	$ 159
Accounts payable and other current liabilities	**1,009**	990
Regulatory liabilities (Note 3)	**76**	43
Current installments of long-term debt	**121**	107
Current installments of capital lease obligations	**3**	3
Deferred income taxes	**3**	5
	1,288	1,307
Other liabilities	**574**	573
Regulatory liabilities (Note 3)	**592**	555
Deferred income taxes	**685**	673
Long-term debt	**5,780**	5,805
Capital lease obligations	**316**	309
	9,235	9,222
Shareholders' equity		
Common shares [(a)] (Note 4)	**3,050**	3,036
Preference shares	**912**	912
Additional paid-in capital	**15**	14
Accumulated other comprehensive loss	**(96)**	(95)
Retained earnings	**932**	868
	4,813	4,735
Non-controlling interests (Note 5)	**246**	208
	5,059	4,943
	$ 14,294	$ 14,165

(a) no par value: unlimited authorized shares; 189.3 million and 188.8 million issued and outstanding as at March 31, 2012 and December 31, 2011, respectively

Commitments and Contingent Liabilities (Notes 17 and 19)
See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Earnings (Unaudited)

For the three months ended March 31

(in millions of Canadian dollars, except per share amounts)

	Quarter Ended	
	2012	2011
Revenue	**$ 1,149**	$ 1,159
Expenses		
Energy supply costs	**566**	603
Operating	**214**	210
Depreciation and amortization	**119**	103
	899	916
Operating income	**250**	243
Other income (expenses), net (Note 8)	**(3)**	8
Finance charges (Note 9)	**91**	92
Earnings before income taxes	**156**	159
Income taxes (Note 10)	**23**	31
Net earnings	**$ 133**	$ 128
Net earnings attributable to:		
Non-controlling interests	**$ 1**	$ 1
Preference equity shareholders	**11**	11
Common equity shareholders	**121**	116
	$ 133	$ 128
Earnings per common share (Note 11)		
Basic	**$ 0.64**	$ 0.66
Diluted	**$ 0.62**	$ 0.64

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Comprehensive Income (Unaudited)

For the three months ended March 31

(in millions of Canadian dollars)

	Quarter Ended	
	2012	2011
Net earnings	**$ 133**	$ 128
Other comprehensive (loss) income		
Unrealized foreign currency translation losses, net of hedging activities and tax	**(2)**	(3)
Unrealized employee future benefits gains, net of tax	**1**	-
	(1)	(3)
Comprehensive income	**$ 132**	$ 125
Comprehensive income attributable to:		
Non-controlling interests	**$ 1**	$ 1
Preference equity shareholders	**11**	11
Common equity shareholders	**120**	113
	$ 132	$ 125

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Cash Flows (Unaudited)
For the three months ended March 31
(in millions of Canadian dollars)

	Quarter Ended 2012	2011
Operating activities		
Net earnings	**$ 133**	$ 128
Items not affecting cash:		
Depreciation - utility capital assets and income producing properties	**107**	95
Amortization - intangible assets	**11**	9
Amortization - other	**1**	(1)
Deferred income taxes	**5**	(2)
Accrued employee future benefits	**4**	4
Equity component of allowance for funds used during construction	**(2)**	(5)
Other	**(14)**	(1)
Change in long-term regulatory assets and liabilities	**4**	18
Change in non-cash operating working capital (Note 13)	**79**	57
	328	302
Investing activities		
Change in other assets and other liabilities	**4**	(2)
Capital expenditures - utility capital assets	**(211)**	(218)
Capital expenditures - income producing properties	**(5)**	(3)
Capital expenditures - intangible assets	**(13)**	(11)
Contributions in aid of construction	**14**	12
Proceeds on sale of utility capital assets and income producing properties	**-**	5
	(211)	(217)
Financing activities		
Change in short-term borrowings	**(83)**	(98)
Repayments of long-term debt and capital lease obligations	**(4)**	(5)
Net borrowings under committed credit facilities	**7**	15
Advances from non-controlling interests	**41**	17
Issue of common shares, net of costs and dividends reinvested	**2**	11
Dividends		
Common shares, net of dividends reinvested	**(44)**	(35)
Preference shares	**(11)**	(11)
Subsidiary dividends paid to non-controlling interests	**(2)**	(2)
	(94)	(108)
Change in cash and cash equivalents	**23**	(23)
Cash and cash equivalents, beginning of period	**87**	107
Cash and cash equivalents, end of period	**$ 110**	$ 84

Supplementary Information to Consolidated Statements of Cash Flows (Note 13)
See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Changes in Equity (Unaudited)

For the three months ended March 31

(in millions of Canadian dollars)

	Common Shares *(Note 4)*	Preference Shares	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Non-Controlling Interests	Total Equity
As at December 31, 2011	**$ 3,036**	**$ 912**	**$ 14**	**$ (95)**	**$ 868**	**$ 208**	**$ 4,943**
Net earnings	**-**	**-**	**-**	**-**	**132**	**1**	**133**
Other comprehensive loss	**-**	**-**	**-**	**(1)**	**-**	**-**	**(1)**
Common share issues	**14**	**-**	**-**	**-**	**-**	**-**	**14**
Stock-based compensation	**-**	**-**	**1**	**-**	**-**	**-**	**1**
Advances from non-controlling interests	**-**	**-**	**-**	**-**	**-**	**41**	**41**
Foreign currency translation impacts	**-**	**-**	**-**	**-**	**-**	**(2)**	**(2)**
Subsidiary dividends paid to non-controlling interests	**-**	**-**	**-**	**-**	**-**	**(2)**	**(2)**
Dividends declared on common shares ($0.30 per share)	**-**	**-**	**-**	**-**	**(57)**	**-**	**(57)**
Dividends declared on preference shares	**-**	**-**	**-**	**-**	**(11)**	**-**	**(11)**
As at March 31, 2012	**$ 3,050**	**$ 912**	**$ 15**	**$ (96)**	**$ 932**	**$ 246**	**$ 5,059**
As at December 31, 2010	$ 2,575	$ 912	$ 12	$ (108)	$ 774	$ 162	$ 4,327
Net earnings	-	-	-	-	127	1	128
Other comprehensive loss	-	-	-	(3)	-	-	(3)
Common share issues	28	-	(1)	-	-	-	27
Stock-based compensation	-	-	1	-	-	-	1
Advances from non-controlling interests	-	-	-	-	-	17	17
Foreign currency translation impacts	-	-	-	-	-	(3)	(3)
Subsidiary dividends paid to non-controlling interests	-	-	-	-	-	(2)	(2)
Dividends declared on common shares ($0.29 per share)	-	-	-	-	(51)	-	(51)
Dividends declared on preference shares	-	-	-	-	(11)	-	(11)
As at March 31, 2011	$ 2,603	$ 912	$ 12	$ (111)	$ 839	$ 175	$ 4,430

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF THE BUSINESS

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following outlines each of the Corporation's reportable segments and is consistent with the basis of segmentation as disclosed in the Corporation's 2011 annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States ("US GAAP").

REGULATED UTILITIES

The Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility are as follows:

a. *Regulated Gas Utilities - Canadian:* Includes the FortisBC Energy companies, which is comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc.

b. *Regulated Electric Utilities - Canadian:* Includes FortisAlberta; FortisBC Electric; Newfoundland Power; and Other Canadian Electric Utilities, which includes Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company, Limited and Algoma Power Inc.

c. *Regulated Electric Utilities - Caribbean:* Includes Caribbean Utilities, in which Fortis holds an approximate 60% controlling ownership interest; wholly owned Fortis Turks and Caicos, which includes FortisTCI Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd.; and Belize Electricity, in which Fortis held an approximate 70% controlling ownership interest up to June 20, 2011. Effective June 20, 2011, the Government of Belize ("GOB") expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011.

NON-REGULATED - FORTIS GENERATION

Fortis Generation includes the financial results of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State.

NON-REGULATED - FORTIS PROPERTIES

Fortis Properties owns and operates 22 hotels, collectively representing 4,300 rooms in eight Canadian provinces, and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

CORPORATE AND OTHER

The Corporate and Other segment includes Fortis net corporate expenses, net expenses of non-regulated FortisBC Holdings Inc. ("FHI") corporate-related activities, and the financial results of FHI's 30% ownership interest in CustomerWorks Limited Partnership "(CWLP") and of FHI's non-regulated wholly owned subsidiary FortisBC Alternative Energy Services Inc. CWLP provides billing and customer care services to utilities, municipalities and certain energy companies. The contracts between CWLP and the FortisBC Energy companies ended on December 31, 2011.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These interim consolidated financial statements have been prepared in accordance with US GAAP for interim financial statements. As a result, these interim consolidated financial statements do not include all of the information and disclosures required in the annual consolidated financial statements and should be read in conjunction with the Corporation's 2011 annual audited consolidated financial statements prepared in accordance with US GAAP and voluntarily filed on the System for Electronic Document Analysis and Retrieval ("SEDAR") by Fortis on March 16, 2012 (the "Corporation's 2011 US GAAP annual audited consolidated financial statements"). In management's opinion, the interim consolidated financial statements include all adjustments that are of a recurring nature and necessary to present fairly the financial position of the Corporation.

Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Because of natural gas consumption patterns, most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Given the diversified group of companies, seasonality may vary.

The preparation of financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates during the three months ended March 31, 2012.

An evaluation of subsequent events through May 1, 2012, the date these interim consolidated financial statements were approved by the Audit Committee of the Board of Directors, was completed to determine whether circumstances warranted recognition and disclosure of events or transactions in the interim consolidated financial statements as at March 31, 2012.

All amounts are presented in Canadian dollars unless otherwise stated.

These interim consolidated financial statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2011 US GAAP annual audited consolidated financial statements, except as described below.

Presentation of Comprehensive Income

Effective January 1, 2012, the Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 220, *Comprehensive Income.* The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. Fortis continues to report the components of comprehensive income in a separate but consecutive statement.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Testing Goodwill for Impairment

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 350, *Goodwill.* The amended standard allows entities testing goodwill for impairment to have the option of performing a qualitative assessment before calculating the fair value of the reporting unit. If the qualitative factors indicate that the fair value of the reporting unit is more likely than not (greater than a 50% chance) to be greater than the carrying value, then the two-step impairment test, including the quantification of the fair value of the reporting unit, would not be required. In adopting the amendments, Fortis will perform a qualitative assessment before calculating the fair value of its reporting units when it performs its annual impairment test on October 1.

Fair Value Measurement

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amended standard improves comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with US GAAP. The amendment does not change what items are measured at fair value but instead makes various changes to the guidance pertaining to how fair value is measured. The above-noted changes did not materially impact the Corporation's consolidated financial statements for the three months ended March 31, 2012.

Changes in Accounting Policies

Effective January 1, 2012, the FortisBC Energy companies prospectively adopted the policy of accruing for non-asset retirement obligation ("non-ARO") removal costs in depreciation expense, as requested in their 2012-2013 Revenue Requirements Applications and subsequently approved by the regulator in its April 2012 rate decision. The accrual of estimated non-ARO removal costs is included in depreciation expense and the provision balance is recognized as a long-term regulatory liability. Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. Non-ARO removal costs are direct costs incurred by the FortisBC Energy companies in taking assets out of service, whether through actual removal of the assets or through disconnection of the assets from the transmission or distribution system. Prior to 2012 non-ARO removal costs, net of salvage proceeds, were recognized in operating expenses as incurred with variances between actual non-ARO removal costs and those forecast for rate-setting purposes recorded in a regulatory deferral account for future recovery from, or refund to, customers in rates commencing in 2012. During the first quarter of 2012, $4 million of non-ARO removal costs were accrued as a part of depreciation expense. During the first quarter of 2011, $3 million of non-ARO removal costs were recognized in operating expenses.

Prior to 2012 variances from forecast, adjusted for certain revenue and cost variances which flowed through to customers, for rate-setting purposes were shared equally between customers and FortisBC Electric. Prospectively from January 1, 2012, the above sharing of positive or negative variances is no longer in effect pursuant to the utility's filed 2012-2013 Revenue Requirements Application, which is subject to regulatory approval and reflects a cost of service rate-setting methodology. Beginning in 2012 variances from forecast for rate-setting purposes related to electricity revenue, purchased power costs and certain other costs, are subject to full deferral account treatment, to be recovered from, or refunded to, customers in future rates and, therefore, are not subject to the sharing mechanism that existed prior to 2012 and do not impact earnings in 2012.

3. REGULATORY ASSETS AND LIABILITIES

A summary of the Corporation's regulatory assets and liabilities is provided below. A detailed description of the nature of the Corporation's regulatory assets and liabilities is provided in Note 7 to the Corporation's 2011 US GAAP annual audited consolidated financial statements.

	As at	
($ millions)	**March 31, 2012**	December 31, 2011
Regulatory assets		
Deferred income taxes	**645**	630
Employee future benefits	**425**	428
Rate stabilization accounts - FortisBC Energy companies	**91**	105
Deferred lease costs - FortisBC Electric	**78**	70
Rate stabilization accounts - electric utilities	**55**	55
Replacement energy deferral - Point Lepreau [(1)]	**47**	47
Deferred energy management costs	**39**	36
Deferred losses on disposal of utility capital assets	**28**	23
Customer Care Enhancement Project cost deferral	**25**	13
Deferred operating overhead costs	**24**	22
Income taxes recoverable on other post-employment benefit ("OPEB") plans	**22**	22
Whistler pipeline contribution deferral	**16**	16
Alberta Electric System Operator ("AESO") charges deferral	**11**	44
Deferred development costs for capital	**11**	11
Pension cost variance deferral	**11**	10
Alternative energy projects cost deferral	**9**	8
Deferred costs - smart meters	**8**	8
Other regulatory assets	**74**	71
Total regulatory assets	**1,619**	1,619
Less: current portion	**(168)**	(219)
Long-term regulatory assets	**1,451**	1,400

[(1)] New Brunswick Power Point Lepreau Nuclear Generating Station

	As at	
($ millions)	**March 31, 2012**	December 31, 2011
Regulatory liabilities		
Non-ARO removal cost provision	**359**	354
Rate stabilization accounts - FortisBC Energy companies	**187**	127
Rate stabilization accounts - electric utilities	**38**	33
Income tax variance deferral	**10**	12
Deferred interest	**10**	10
AESO charges deferral	**9**	12
Southern Crossing Pipeline deferral	**7**	8
Performance-based rate-setting incentive liabilities	**6**	7
Unrecognized net gains on disposal of utility capital assets	**6**	6
Other regulatory liabilities	**36**	29
Total regulatory liabilities	**668**	598
Less: current portion	**(76)**	(43)
Long-term regulatory liabilities	**592**	555

4. COMMON SHARES

Common shares issued during the period were as follows:

	Quarter Ended March 31, 2012 Number of Shares *(in thousands)*	Amount *($ millions)*
Balance, beginning of period	**188,828**	**3,036**
Dividend Reinvestment Plan	**400**	**13**
Consumer Share Purchase Plan	**13**	**-**
Stock Option Plans	**33**	**1**
Balance, end of period	**189,274**	**3,050**

5. NON-CONTROLLING INTERESTS

	Quarter Ended March 31	
($ millions)	**2012**	2011
Waneta Expansion Limited Partnership ("Waneta Partnership")	**157**	128
Caribbean Utilities	**70**	73
Mount Hayes Limited Partnership (Note 17)	**12**	-
Preference shares of Newfoundland Power	**7**	7
	246	208

6. STOCK-BASED COMPENSATION PLANS

In January 2012 21,417 Deferred Share Units ("DSUs") were granted to the Corporation's Board of Directors, representing the equity component of the Directors' annual compensation and, where opted, their annual retainers in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation.

In March 2012 44,863 Performance Share Units ("PSUs") were paid out to the President and Chief Executive Officer ("CEO") of the Corporation at $32.14 per PSU, for a total of approximately $1.4 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2009 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors of Fortis.

Stock-based compensation expense of $1.2 million was recognized for the three months ended March 31, 2012 ($1.5 million for the three months ended March 31, 2011).

7. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans and defined contribution pension plans, including group registered retirement savings plans for employees. The Corporation and certain subsidiaries also offer OPEB plans for qualifying employees. The net benefit cost of providing the defined benefit pension and OPEB plans is detailed in the following table.

	Quarter Ended March 31			
	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2012**	2011	**2012**	2011
Components of net benefit cost:				
Service costs	**7**	5	**2**	1
Interest costs	**12**	12	**3**	3
Expected return on plan assets	**(12)**	(12)	**-**	-
Amortization of actuarial losses	**6**	5	**1**	1
Amortization of past service costs/plan amendments	**-**	-	**(1)**	(1)
Regulatory adjustments	**(1)**	(2)	**1**	1
Net benefit cost	**12**	8	**6**	5

For the three months ended March 31, 2012, the Corporation expensed $4 million ($4 million for the three months ended March 31, 2011) related to defined contribution pension plans.

8. OTHER INCOME (EXPENSES), NET

	Quarter Ended March 31	
($ millions)	**2012**	2011
Equity component of allowance for funds used during construction	**2**	5
Interest income	**1**	1
Net foreign exchange loss	**(2)**	-
Acquisition-related expenses	**(4)**	-
Other income, net of expenses	**-**	2
	(3)	8

The net foreign exchange loss includes an approximate $1.5 million foreign exchange loss on the translation into Canadian dollars of the Corporation's long-term other asset associated with Belize Electricity (Note 18).

The acquisition-related expenses are associated with the proposed acquisition of CH Energy Group, Inc. ("CH Energy Group"), as announced by the Corporation on February 21, 2012.

9. FINANCE CHARGES

	Quarter Ended March 31	
($ millions)	**2012**	2011
Interest - Long-term debt and capital lease obligations	**94**	93
- Short-term borrowings and other	**1**	4
Debt component of allowance for funds used during construction	**(4)**	(5)
	91	92

10. INCOME TAXES

Income taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

	Quarter Ended March 31	
($ millions, except as noted)	**2012**	2011
Combined Canadian federal and provincial statutory income tax rate	**29.0%**	30.5%
Statutory income tax rate applied to earnings before income taxes	**45**	48
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(5)**	(5)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(1)**	(2)
Items capitalized for accounting purposes but expensed for income tax purposes	**(19)**	(16)
Difference between capital cost allowance and amounts claimed for accounting purposes	**3**	2
Non-deductible expenses	**1**	1
Difference between enacted and substantially enacted income tax rates associated with Part VI.1 tax	**-**	1
Other	**(1)**	2
Income taxes	**23**	31
Effective tax rate	**14.7%**	19.5%

As at March 31, 2012, the Corporation had approximately $96 million (December 31, 2011 - $86 million) in non-capital and capital loss carryforwards, of which $13 million (December 31, 2011 - $13 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2032.

11. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

	Quarter Ended March 31					
	2012			2011		
	Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares *(in millions)***	**EPS**	Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**121**	**189.0**	**$ 0.64**	116	175.0	$ 0.66
Effect of potential dilutive securities:						
Stock Options	**-**	**1.0**		-	1.2	
Preference Shares	**4**	**10.3**		4	10.1	
Convertible Debentures	**-**	**-**		1	1.4	
Diluted EPS	**125**	**200.3**	**$ 0.62**	121	187.7	$ 0.64

12. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Quarter Ended March 31, 2012 *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**548**	108	87	192	91	**478**	**63**	**9**	**52**	**6**	**(7)**	**1,149**
Energy supply costs	**302**	-	25	142	58	**225**	**40**	**-**	**-**	**-**	**(1)**	**566**
Operating expenses	**70**	39	21	20	12	**92**	**8**	**3**	**40**	**3**	**(2)**	**214**
Depreciation and amortization	**40**	35	12	11	7	**65**	**7**	**1**	**5**	**1**	**-**	**119**
Operating income	**136**	34	29	19	14	**96**	**8**	**5**	**7**	**2**	**(4)**	**250**
Other income (expenses), net	**-**	2	-	-	-	**2**	**-**	**1**	**-**	**(5)**	**(1)**	**(3)**
Finance charges	**35**	15	10	9	5	**39**	**4**	**1**	**6**	**11**	**(5)**	**91**
Income tax expense (recovery)	**19**	-	3	3	2	**8**	**-**	**-**	**-**	**(4)**	**-**	**23**
Net earnings (loss)	**82**	21	16	7	7	**51**	**4**	**5**	**1**	**(10)**	**-**	**133**
Non-controlling interests	**-**	-	-	-	-	**-**	**1**	**-**	**-**	**-**	**-**	**1**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**11**	**-**	**11**
Net earnings (loss) attributable to common equity shareholders	**82**	21	16	7	7	**51**	**3**	**5**	**1**	**(21)**	**-**	**121**
Goodwill	**913**	227	221	-	63	**511**	**139**	**-**	**-**	**-**	**-**	**1,563**
Identifiable assets	**4,621**	2,476	1,677	1,266	690	**6,109**	**708**	**612**	**612**	**468**	**(399)**	**12,731**
Total assets	**5,534**	2,703	1,898	1,266	753	**6,620**	**847**	**612**	**612**	**468**	**(399)**	**14,294**
Gross capital expenditures [(1)]	**46**	79	17	15	9	**120**	**10**	**48**	**5**	**-**	**-**	**229**
Quarter Ended March 31, 2011 *($ millions)*												
Revenue	**574**	100	83	183	91	**457**	**75**	**7**	**50**	**6**	**(10)**	**1,159**
Energy supply costs	**344**	-	23	134	60	**217**	**46**	**-**	**-**	**-**	**(4)**	**603**
Operating expenses	**74**	35	18	20	12	**85**	**11**	**3**	**37**	**2**	**(2)**	**210**
Depreciation and amortization	**27**	33	11	10	6	**60**	**9**	**1**	**5**	**1**	**-**	**103**
Operating income	**129**	32	31	19	13	**95**	**9**	**3**	**8**	**3**	**(4)**	**243**
Other income (expenses), net	**3**	3	1	-	-	**4**	**1**	**1**	**-**	**-**	**(1)**	**8**
Finance charges	**34**	13	10	9	5	**37**	**5**	**1**	**6**	**14**	**(5)**	**92**
Income tax expense (recovery)	**23**	1	3	4	2	**10**	**-**	**-**	**1**	**(3)**	**-**	**31**
Net earnings (loss)	**75**	21	19	6	6	**52**	**5**	**3**	**1**	**(8)**	**-**	**128**
Non-controlling interests	**-**	-	-	-	-	**-**	**1**	**-**	**-**	**-**	**-**	**1**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**11**	**-**	**11**
Net earnings (loss) attributable to common equity shareholders	**75**	21	19	6	6	**52**	**4**	**3**	**1**	**(19)**	**-**	**116**
Goodwill	**913**	227	221	-	63	**511**	**133**	**-**	**-**	**-**	**-**	**1,557**
Identifiable assets	**4,397**	2,188	1,613	1,244	658	**5,703**	**775**	**422**	**576**	**473**	**(416)**	**11,930**
Total assets	**5,310**	2,415	1,834	1,244	721	**6,214**	**908**	**422**	**576**	**473**	**(416)**	**13,487**
Gross capital expenditures [(1)]	**48**	85	30	14	8	**137**	**21**	**23**	**3**	**-**	**-**	**232**

[(1)] Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statements of cash flows

12. SEGMENTED INFORMATION (cont'd)

Related party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions primarily related to: (i) the sale of energy from Fortis Generation to Belize Electricity, up to June 20, 2011; (ii) electricity sales from Newfoundland Power to Fortis Properties; and (iii) finance charges on related party borrowings. The significant related party inter-segment transactions for the three months ended March 31, 2012 and 2011 were as follows:

Significant Inter-Segment Transactions	**Quarter Ended March 31**	
($ millions)	**2012**	2011
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	**-**	4
Sales from Newfoundland Power to Fortis Properties	**2**	1
Inter-segment finance charges on lending from:		
Corporate to Regulated Electric Utilities - Caribbean	**1**	1
Corporate to Fortis Generation	**-**	1
Corporate to Fortis Properties	**4**	3

The significant inter-segment asset balances were as follows:

	As at March 31	
($ millions)	**2012**	2011
Inter-segment lending from:		
Fortis Generation to Other Canadian Electric Utilities	**20**	20
Corporate to Regulated Electric Utilities - Canadian	**-**	50
Corporate to Regulated Electric Utilities - Caribbean	**76**	58
Corporate to Fortis Generation	**20**	50
Corporate to Fortis Properties	**257**	222
Other inter-segment assets	**26**	16
Total inter-segment eliminations	**399**	416

13. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

	Quarter Ended March 31	
($ millions)	**2012**	2011
Cash paid for:		
Interest	**80**	81
Income taxes	**33**	24
Change in non-cash operating working capital:		
Accounts receivable	**(59)**	(36)
Prepaid expenses	**2**	(1)
Regulatory assets - current portion	**43**	(5)
Inventories	**58**	80
Accounts payable and other current liabilities	**9**	(7)
Regulatory liabilities - current portion	**26**	26
	79	57
Non-cash investing and financing activities:		
Common share dividends reinvested	**13**	16
Additions to utility capital assets included in accounts payable	**7**	41
Exercise of stock options into common shares	**-**	1

14. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Corporation generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. As at March 31, 2012, the Corporation's derivative contracts consisted of a foreign exchange forward contract, natural gas swap and option contracts, and gas purchase contract premiums, all held by the FortisBC Energy companies.

Volume of Derivative Activity

As at March 31, 2012, FEI and FEVI had the following notional volumes related to an outstanding foreign exchange forward contract and natural gas derivatives, designated for regulatory approval, that are expected to be settled as outlined below.

	2012	2013	2014
Foreign Exchange Forward Contract:			
Cash exposure *($ millions)*	1	-	-
Weighted average CDN$ to US$ exchange rate	1.00	-	-
Natural Gas Derivatives:			
Swaps and options *(petajoules)*	26	18	7
Gas purchase contract premiums *(petajoules)*	70	20	9

Presentation of Derivative Instruments in the Consolidated Financial Statements

In the Corporation's consolidated balance sheets, derivative instruments are presented on a net basis by counterparty, where the right of offset exists. The net balances include outstanding cash collateral associated with derivative positions.

The Corporation's outstanding derivative balances were as follows:

	As at	
($ millions)	**March 31, 2012**	December 31, 2011
Gross derivatives balance (1)	**132**	136
Netting (2)	**-**	-
Cash collateral	**-**	-
Total derivative balances (3)	**132**	136

(1) Refer to Note 15 for a discussion of the valuation techniques used to calculate the fair value of these derivative instruments.
(2) Positions, by counterparty, are netted where the intent and legal right to offset exists.
(3) Unrealized losses of $132 million on commodity risk-related derivative instruments were recognized as current regulatory assets as at March 31, 2012 (December 31, 2011 - $135 million), which would otherwise be recognized on the consolidated statement of comprehensive income or as accumulated other comprehensive loss. These amounts exclude the impact of cash collateral postings.

Cash flows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's consolidated statements of cash flows.

The majority of the FortisBC Energy companies' risk-related derivative instruments contain collateral posting provisions tied to FEI's credit rating. A downgrade of FEI below investment grade by any of the major credit rating agencies could trigger margin calls and other cash requirements under FEI's gas purchase, swap and option contracts. Most of the existing natural gas derivative contracts are in liability positions and might be subject to margin calls and other cash requirements if FEI was downgraded below investment grade.

15. FAIR VALUE MEASUREMENTS

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value. The Corporation is required to determine the fair value of all derivative instruments.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets
Level 2: Fair value determined using pricing inputs that are observable
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available

The fair values of the Corporation's financial instruments, including derivatives, reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The following table details the estimated fair value measurements of the Corporation's financial instruments, all of which were measured using Level 2 inputs.

	As at			
Asset (Liability)	**March 31, 2012**		December 31, 2011	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Other asset - Belize Electricity [(1)]	**104**	**-** [(2)]	106	- [(2)]
Long-term debt, including current portion	**(5,901)**	**(7,207)**	(5,912)	(7,296)
Waneta Partnership promissory note [(3)]	**(45)**	**(50)**	(45)	(49)
Foreign exchange forward contract [(4)]	**-**	**-**	-	-
Fuel option contracts [(4)]	**-**	**-**	(1)	(1)
Natural gas derivatives: [(4)]				
Swaps and options	**(135)**	**(135)**	(135)	(135)
Gas purchase contract premiums	**3**	**3**	-	-

(1) Included in long-term other assets on the consolidated balance sheet
(2) The fair value of the Corporation's expropriated investment in Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's independent valuation of the utility. Due to uncertainty in the ultimate amount and ability of the GOB to pay compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the long-term other asset at the carrying value of the Corporation's previous investment in Belize Electricity, including foreign exchange impacts.
(3) Included in long-term other liabilities on the consolidated balance sheet
(4) The fair values of the derivatives were recorded in accounts payable and other current liabilities as at March 31, 2012 and December 31, 2011.

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

15. FAIR VALUE MEASUREMENTS (cont'd)

The fair value of the foreign exchange forward contract was calculated using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. Any change in the fair value of the foreign exchange forward contract at FEI was deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The fuel option contracts were used by Caribbean Utilities to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. The fuel option contracts matured in March 2012.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the FortisBC Energy companies have floating, rather than fixed, prices. Any resulting gains or losses were recorded in regulatory assets or liabilities in the consolidated balance sheet. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The fair values of the foreign exchange forward contract and the natural gas derivatives were estimates of the amounts that the FortisBC Energy companies would have had to receive or pay to terminate the outstanding contracts as at the balance sheet date. As at March 31, 2012, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

16. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit Risk	Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity Risk	Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market Risk	Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash equivalents, trade and other accounts receivable, and other long-term receivables, the Corporation's credit risk is limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at March 31, 2012, the utility's gross credit risk exposure was approximately $156 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $9 million by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

16. FINANCIAL RISK MANAGEMENT (cont'd)

Credit Risk (cont'd)

The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. To help mitigate credit risk, the FortisBC Energy companies deal with high credit-quality institutions in accordance with established credit-approval practices. The counterparties with which the FortisBC Energy companies have significant transactions are A-rated entities or better. The Company uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

The following table summarizes the FortisBC Energy companies' net credit risk exposure to its counterparties, as well as credit risk exposure to counter parties accounting for greater than 10% net credit exposure.

	As at	
($ millions, except for number of customers)	**March 31, 2012**	December 31, 2011
Gross credit exposure before credit collateral [(1)]	**136**	136
Credit collateral	**-**	-
Net credit exposure [(2)]	**136**	136
Number of counterparties > 10%	**4**	4
Net exposure to counterparties > 10%	**99**	104

[(1)] Gross credit exposure equals mark-to-market value on physically and financially settled contracts, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported do not include adjustments for time value or liquidity.
[(2)] Net credit exposure is the gross credit exposure collateral minus credit collateral (cash deposits and letters of credit).

The Corporation is exposed to credit risk associated with the amount and timing of compensation that Fortis is entitled to receive from the GOB as a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB on June 20, 2011. The Corporation has a long-term other asset of $104 million, including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Note 18).

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at March 31, 2012, average annual consolidated long-term debt maturities and repayments over the next five years are expected to be approximately $265 million. The combination of available credit facilities and relatively low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

16. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

As at March 31, 2012, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which $2.0 billion was unused. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities.

The following table outlines the credit facilities of the Corporation and its subsidiaries.

				As at	
($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**March 31, 2012**	December 31, 2011
Total credit facilities	845	1,389	13	**2,247**	2,248
Credit facilities utilized:					
Short-term borrowings [1]	-	(73)	(3)	**(76)**	(159)
Long-term debt [2]	(31)	(50)	-	**(81)**	(74)
Letters of credit outstanding	(1)	(65)	-	**(66)**	(66)
Credit facilities unused	813	1,201	10	**2,024**	1,949

[1] The weighted average interest rate on short-term borrowings was approximately 1.7% as at March 31, 2012 (December 31, 2011 - 1.2%).

[2] As at March 31, 2012, credit facility borrowings classified as long-term included $16 million (December 31, 2011 - $16 million) that was included in current installments of long-term debt on the consolidated balance sheet. The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 2.0% as at March 31, 2012 (December 31, 2011 - 2.1%).

As at March 31, 2012 and December 31, 2011, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In March 2012 Newfoundland Power renegotiated and amended its $100 million unsecured committed credit facility, obtaining an extension to the maturity of the facility to August 2017 from August 2015. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In April 2012 FortisBC Electric renegotiated and amended its credit facility agreement resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2015 and $50 million now maturing in May 2013.

Fortis has requested an increase in the amount available for borrowing under its committed corporate credit facility from $800 million to $1 billion, as permitted under the credit facility agreement, and expects the increase to be available in May 2012.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at March 31, 2012, the Corporation's credit ratings are as follows:

Standard & Poor's	A-/Credit Watch - Negative (unsecured debt credit rating)
DBRS	A(low)/Under Review - Developing Implications (unsecured debt credit rating)

The above credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis. In February 2012, after the announcement by Fortis that it had entered into an agreement to acquire CH Energy Group, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P placed the Corporation's credit rating on credit watch with negative implications.

16. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk

Foreign Exchange Risk
The Corporation's earnings from, and net investment in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar.

As at March 31, 2012, the Corporation's corporately issued US$550 million (December 31, 2011 - US$550 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at March 31, 2012, the Corporation had approximately US$8 million (December 31, 2011 - US$6 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings that are designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. As a result, the Corporation recognized a foreign exchange loss of approximately $1.5 million in earnings during the three months ended March 31, 2012 (Note 8).

FEI's US dollar payments under a contract for the implementation of a customer care information system are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. FEI entered into a foreign exchange forward contract to hedge this exposure. FEI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates.

Interest Rate Risk
The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

Commodity Price Risk
The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk has been minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The natural gas derivatives are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

16. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk (cont'd)

Commodity Price Risk (cont'd)
The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive with electricity rates, temper gas price volatility on customer rates and reduce the risk of regional price discrepancies. In 2011 the BCUC determined that commodity hedging in the current environment was not a cost-effective means to meet the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011-2014 Price Risk Management Plan ("PRMP") with the exception of certain elements to address regional price discrepancies. As a result, the FortisBC Energy companies have suspended all commodity hedging activities, with the exception of certain limited swaps as permitted by the BCUC. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. Any differences between the cost of natural gas purchased and the price of natural gas included in customer rates are recorded as regulatory deferrals and are recovered from, or refunded to, customers in future rates, subject to regulatory approval.

17. COMMITMENTS

There were no material changes in the nature and amount of the Corporation's commitments from the commitments disclosed in the Corporation's 2011 US GAAP annual audited consolidated financial statements, except as described below.

In January 2012 two First Nations bands each invested approximately $6 million in equity in the Mount Hayes liquefied natural gas storage facility, representing a 15% equity interest in the Mount Hayes Limited Partnership, with FEVI holding the controlling 85% ownership interest (Note 5). The non-controlling interests hold put options, which, if exercised, would require FEVI to repurchase the 15% ownership interest for cash, in accordance with the terms of the partnership agreement.

In April 2012 the December 31, 2011 actuarial valuation of the defined benefit pension plan at Newfoundland Power was completed. As a result Newfoundland Power is required to fund a solvency deficiency of approximately $53.5 million, including interest, over five years beginning in 2012. The increase in funding contributions is expected to be recovered from customers in future rates.

18. EXPROPRIATED ASSETS

Belize Electricity
On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation has discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011, and has classified the book value of the previous investment in the utility as a long-term other asset on the interim consolidated balance sheet.

In October 2011 Fortis commenced an action in the Belize Supreme Court with respect to the challenge of the legality of the expropriation of the Corporation's investment in Belize Electricity and court proceedings are continuing. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011.

18. EXPROPRIATED ASSETS (cont'd)

Belize Electricity (cont'd)
The GOB also commissioned a valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation from the GOB.

Exploits Partnership
The Exploits Partnership is owned 51% by Fortis Properties and 49% by AbitibiBowater Inc. ("Abitibi"). The Exploits Partnership operated two non-regulated hydroelectric generating facilities in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

19. CONTINGENT LIABILITIES

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Fortis
Following the announcement of the proposed acquisition of CH Energy Group on February 21, 2012, several complaints, which named Fortis and other defendants, were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, challenging the proposed acquisition. The complaints generally allege that the directors of CH Energy Group breached their fiduciary duties in connection with the proposed transaction and that CH Energy Group, Fortis, FortisUS Inc., and Cascade Acquisition Sub Inc. aided and abetted that breach.

The outcome of these lawsuits is uncertain and cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements. An adverse judgment for monetary damages could have a material adverse effect on the operations of the surviving company after the completion of the acquisition. A preliminary injunction could delay or jeopardize the completion of the acquisition and an adverse judgment granting permanent injunctive relief could indefinitely enjoin completion of the transaction. Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of such lawsuits is not expected to have a material adverse effect on the consolidated financial condition of Fortis. The defendants intend to vigorously defend themselves against the lawsuits.

FHI
During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. FHI has begun the appeal process associated with the assessments.

19. CONTINGENT LIABILITIES (cont'd)

FHI (cont'd)
In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric
The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements. A date for mediation of this matter has been set for December 2012.

Dates – Dividends* and Earnings

Expected Earnings Release Dates

July 31, 2012	November 1, 2012
February 7, 2013	May 1, 2013

Dividend Record Dates

May 17, 2012	August 17, 2012
November 16, 2012	February 14, 2013

Dividend Payment Dates

June 1, 2012	September 1, 2012
December 1, 2012	March 1, 2013

* *The declaration and payment of dividends are subject to Board of Directors' approval.*

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Share Listings

The Common Shares, First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G and First Preference Shares, Series H of Fortis Inc. are traded on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively.

Fortis Common Shares ($) Quarter Ended March 31		
	2012	**2011**
High	**34.31**	**35.45**
Low	**31.70**	**31.53**
Close	**32.27**	**33.12**

TransCanada Reports First Quarter Results, Bruce Power Refurbishment Nearing Completion

CALGARY, Alberta – **April 27, 2012** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced comparable earnings for first quarter 2012 of $363 million or $0.52 per share. Net income attributable to common shares for first quarter 2012 was $352 million or $0.50 per share. TransCanada's Board of Directors also declared a quarterly dividend of $0.44 per common share for the quarter ending June 30, 2012, equivalent to $1.76 per common share on an annualized basis.

"TransCanada continued to produce solid earnings in a challenging environment," said Russ Girling, TransCanada's president and chief executive officer. "A very warm winter, historically low natural gas prices and planned maintenance outages at Bruce Power impacted earnings in the first quarter of 2012. The return to service of two refurbished nuclear reactors at Bruce Power and the contribution from other new assets position TransCanada well for the future. As gas and power prices recover, combined with the completion of our current $13 billion capital program, I fully expect TransCanada will continue to grow cash flow, earnings and dividends in the years ahead."

Over the next three years, TransCanada expects to complete $13 billion of projects that are in the advanced stages of development - $7.8 billion in oil pipelines, $2.2 billion in natural gas pipelines and $3 billion in energy. They include: the re-start of two reactors at Ontario's Bruce nuclear facility, the Keystone Gulf Coast Project and Keystone XL, the Keystone Bakken Marketlink Project, the Keystone Hardisty Terminal Project, additional extensions and expansions of the Alberta System, the Tamazunchale natural gas pipeline extension in Mexico, the final phase of the Cartier Wind power project in Québec and the acquisition of nine Ontario solar projects.

To date, the Company has spent approximately $6 billion on these low-risk energy infrastructure assets and is well positioned to fund the remainder of this capital program from internally generated cash flow and debt capacity. TransCanada expects these assets to generate significant, sustained earnings and cash flow growth and deliver superior returns to its shareholders.

Highlights

(All financial figures are unaudited and in Canadian dollars unless noted otherwise)

- First quarter financial results
  - Comparable earnings of $363 million or $0.52 per share
  - Net income attributable to common shares of $352 million or $0.50 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.1 billion
  - Funds generated from operations of $841 million
- Declared a quarterly dividend per common share of $0.44 for the quarter ending June 30
- Bruce Power entered the final phase of the refurbishment and re-start project. TransCanada's share of the project costs is expected to be approximately $2.4 billion
- Advanced a number of initiatives in the Oil Pipelines business
  - Announced plans to build the US$2.3 billion Gulf Coast Project to transport crude oil from Cushing, Oklahoma to Gulf Coast refineries
  - Announced commitment to re-file a Presidential Permit application for the Keystone XL Project from the U.S./Canada border to Steele City, Nebraska

  - Launched and concluded a binding open season for the Keystone Hardisty Terminal to store and deliver crude oil to the Keystone Pipeline System
- Awarded a contract to build a US$500 million extension of the Tamazunchale natural gas pipeline in Mexico

Comparable earnings for first quarter 2012 were $363 million or $0.52 per share compared to $423 million or $0.61 per share for the same period in 2011. Incremental earnings from Keystone and other recently commissioned assets were more than offset by lower contributions from Bruce Power related to planned maintenance outages, reduced revenues from U.S. natural gas pipelines and natural gas storage, higher interest expense as a result of lower capitalized interest and reduced contributions from the Canadian Mainline and U.S. Power.

Net income attributable to common shares for first quarter 2012 was $352 million or $0.50 per share compared to $411 million or $0.59 per share in first quarter 2011.

Notable recent developments in Oil Pipelines, Natural Gas Pipelines, Energy and Corporate include:

Oil Pipelines:

- The Company announced in February 2012 that what had previously been the Cushing to U.S. Gulf Coast portion of the Keystone XL Project has its own independent value to the marketplace and will be constructed as the stand-alone Gulf Coast Project, not part of the Presidential Permit process. The approximate cost of the 36-inch line is US$2.3 billion and, subject to regulatory approvals, TransCanada expects the Gulf Coast Project to be in service in mid to late 2013. As of March 31, 2012, US$800 million has been invested in the project. Included in the US$2.3 billion cost is US$300 million for the 76-kilometre (km) (47-mile) Houston Lateral pipeline that will transport oil to Houston refineries.

  U.S. crude oil production has been growing significantly in States such as Oklahoma, Texas, North Dakota and Montana. Producers do not have access to enough pipeline capacity to move this production to the large refining market at the U.S. Gulf Coast. The Gulf Coast Project will address this constraint.

- Also in February, TransCanada sent a letter to the U.S. Department of State (DOS) informing the Department the Company plans to re-file a Presidential Permit application (cross border permit) in the near future for the Keystone XL Project from the U.S./Canada border in Montana to Steele City, Nebraska. TransCanada noted it would supplement that application with an alternative route in Nebraska as soon as that route is selected.

  The application will include the already reviewed route in Montana and South Dakota. The over three year environmental review for Keystone XL completed last summer was the most comprehensive process ever for a cross border pipeline. Based on that work, TransCanada expects its cross border permit should be processed expeditiously and a decision made once a new route in Nebraska is determined.

  Earlier this month, legislation was passed in Nebraska and signed into law by the Governor that enabled TransCanada to re-engage with the State's Department of Environmental Quality (DEQ), allowing the Company to continue to work collaboratively in determining an alternative route for Keystone XL that avoids the Sandhills. Alternative routing corridors and a preferred corridor were submitted to the DEQ April 18, 2012. The Department will now oversee the public comment and review process as TransCanada develops a specific alternate route.

The capital cost of Keystone XL is estimated to be US$5.3 billion, with US$1.5 billion having been invested as of March 31, 2012. The remainder will be spent between now and the in-service date of the expansion, which is expected by late 2014 or early 2015.

- In March 2012, TransCanada launched and concluded an open season to obtain binding commitments for the Keystone Hardisty Terminal. The two million barrel project located at Hardisty, Alberta will provide new infrastructure for Western Canadian producers and access to the Keystone Pipeline System. TransCanada is currently reviewing the results of the open season. The Keystone Hardisty Terminal is expected to be operational by late 2014 or early 2015.

Natural Gas Pipelines:

- The National Energy Board (NEB) approved $330 million of expansion projects for the Alberta System in first quarter 2012 which is a portion of the previously reported $810 million of projects for the Alberta System filed in 2011 – the balance of which are still awaiting approval.

  TransCanada's Alberta System has incremental, firm commitments to transport approximately 3.4 billion cubic feet per day (Bcf/d) from western Alberta and northeast B.C. by 2014. Further requests for additional volumes on the Alberta System from the northwest portion of the Western Canada Sedimentary Basin (WCSB) have been received.

  In addition, infrastructure to connect WCSB supply to markets continues to be pursued, particularly to support further development of Alberta oil sands production and to supply proposed liquefied natural gas (LNG) export facilities on the West Coast.

  During the first four months of 2012, TransCanada has substantially completed 10 separate pipeline projects for the Alberta System at a cost of approximately $600 million.

- On June 4, 2012, an NEB hearing will begin to discuss TransCanada's application to change the business structure and the terms and conditions of service for the Canadian Mainline, including addressing tolls for 2012 and 2013. The hearing is expected to conclude in September with a decision in late 2012 or early 2013.

  TransCanada is working to construct new pipeline infrastructure to provide Southern Ontario with additional natural gas supply from the Marcellus shale basin. The NEB is continuing to assess the application for the project that was filed late last fall. Assuming the project receives approval to proceed, construction is scheduled to begin in early July 2012, with planned completion in November 2012. The capital cost of the Marcellus Facilities Expansion is expected to be approximately $130 million.

  An open season to attract new capacity on the Canadian Mainline to capture additional Marcellus gas supply will close in May. It is being held in response to shippers who have expressed interest in acquiring additional transport capacity.

- On February 24, 2012, the Company was chosen to build, own and operate the Tamazunchale Pipeline Extension in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract with the Comisión Federal de Electricidad (CFE), Mexico's state-owned power company.

TransCanada anticipates investing approximately US$500 million in the pipeline and expects it will be operational in the first quarter of 2014. The 235-km (146-mile) long pipeline has a contracted capacity of 630 million cubic feet a day (mmcf/d). The pipeline will originate at the end of TransCanada's existing Tamazunchale Pipeline, eventually connecting with Mexico's existing pipeline grid and serve a CFE combined-cycle power generating facility.

The Tamazunchale Pipeline Extension demonstrates TransCanada's continued commitment to developing Mexico's energy infrastructure to meet growing requirements for increased natural gas supply. The Mexican government recently announced a number of additional natural gas infrastructure projects for the country. This infrastructure will assist Mexico in meeting growing demand and support greenhouse gas reduction initiatives by enabling access to natural gas as a replacement fuel for heavy oil. TransCanada intends to continue to pursue future development opportunities in Mexico.

- The Alaska North Slope producers (Exxon Mobil Corporation, ConocoPhillips and BP), along with TransCanada through its participation in the Alaska Pipeline Project, announced in March 2012 the companies have agreed on a work plan aimed at commercializing North Slope natural gas resources through an LNG option. This would involve construction of a natural gas pipeline from the North Slope to Valdez, Alaska where the gas would be liquefied and shipped to international markets.

Energy:

- Bruce Power received authorization from the Canadian Nuclear Safety Commission on March 16, 2012 to power up the Unit 2 reactor, effectively ending the construction and commissioning phases of the project. This positive development represented the final major step necessary toward bringing the reactor into service.

  The reactor is presently producing steam and final safety checks are being conducted. The company anticipates the unit will start commercial operations in second quarter 2012. Refurbishment of the Unit 1 reactor at Bruce Power is also progressing and it is expected to begin commercial operations in mid-third quarter 2012.

  TransCanada's share of the net capital cost of the refurbishment is expected to be approximately $2.4 billion. Once the work is complete, Bruce Power will be one of the world's largest nuclear facilities, generating more than 6,200 megawatts (MW) or about 25 per cent of Ontario's power.

- The 111 MW second phase of Gros-Morne is expected to be operational in December 2012. Its construction will signal the completion of the 590 MW, five-phase Cartier Wind project in Québec. The project is 62 per cent owned by TransCanada and all of the power produced by Cartier Wind is sold under a 20-year power purchase arrangement (PPA) to Hydro-Québec.

- Late in 2011, TransCanada agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 MW, for approximately $470 million. All nine projects have 20-year power purchase agreements with the Ontario Power Authority.

  Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. utilizing their photovoltaic panels. TransCanada will purchase each project after they begin commercial operation and meet certain milestones. TransCanada anticipates the projects will be operational between late 2012 and mid-2013.

- TransAlta filed a force majeure claim in January 2011 following the shut down of Sundance A Units 1 and 2 in December 2010. In February 2011, TransAlta notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2 and that the Sundance A PPA should be terminated.

  TransCanada has disputed both the force majeure and economic destruction claims. An arbitration process to resolve the matter began in early April and is expected to conclude in May, with a decision anticipated in mid-2012.

  TransCanada has continued to record revenues and costs as it considers this event to be an interruption of supply. The Company believes the matter will be resolved in its favour.

Corporate:

- In March 2012, TransCanada PipeLines Limited issued Senior Notes of US$500 million maturing on March 2, 2015 and bearing interest at an annual rate of 0.875 per cent. The net proceeds of this offering were used for general corporate purposes and to reduce short-term indebtedness.

- The Board of Directors of TransCanada declared a quarterly dividend of $0.44 per share for the quarter ending June 30, 2012 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $1.76 per common share on an annual basis.

- As previously disclosed, TransCanada adopted U.S. generally accepted accounting principles (U.S. GAAP) effective January 1, 2012. Accordingly, first quarter 2012 financial information, along with comparative financial information for 2011, has been prepared in accordance with U.S. GAAP.

Teleconference – Audio and Slide Presentation:

TransCanada will hold a teleconference and webcast to discuss its 2012 first quarter financial results. Russ Girling, TransCanada president and chief executive officer and Don Marchand, executive vice-president and chief financial officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments before opening the call to questions from analysts and members of the media.

Event:
TransCanada 2012 first quarter financial results teleconference and webcast

Date:
Friday, April 27, 2012

Time:
1 p.m. mountain daylight time (MDT) / 3 p.m. eastern daylight time (EDT)

Analysts, members of the media and other interested parties are invited to participate by calling 866.226.1792 or 416.340.2216 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EDT) May 4, 2012. Please call 905.694.9451 or 800.408.3053 (North America only) and enter pass code 8130635.

With more than 60 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 68,500 kilometres (42,500 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with approximately 380 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 10,800 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest oil delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. For more information visit: www.transcanada.com or check us out on Twitter @TransCanada.

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First Quarter 2012 Financial Highlights

Operating Results

Three months ended March 31 *(unaudited)* *(millions of dollars)*	2012	2011
Revenues	**1,911**	1,868
Comparable EBITDA[1]	**1,113**	1,163
Net Income Attributable to Common Shares	**352**	411
Comparable Earnings[1]	**363**	423
Cash Flows		
Funds generated from operations[1]	**841**	815
(Increase)/decrease in operating working capital	**(169)**	19
Net cash provided by operations	**672**	834
Capital Expenditures	**464**	567

Common Share Statistics

Three months ended March 31 *(unaudited)*	2012	2011
Net Income per Common Share - Basic	**$0.50**	$0.59
Comparable Earnings per Common Share[1]	**$0.52**	$0.61
Dividends Declared per Common Share	**$0.44**	$0.42
Basic Common Shares Outstanding (millions)		
Average for the period	**704**	698
End of period	**704**	700

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA, Comparable Earnings, Funds Generated from Operations and Comparable Earnings per Share.

TRANSCANADA CORPORATION – FIRST QUARTER 2012

Quarterly Report to Shareholders

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) dated April 26, 2012 should be read in conjunction with the accompanying unaudited Condensed Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) for the three months ended March 31, 2012. The condensed consolidated financial statements of the Company have been prepared in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP). Comparative figures, which were previously presented in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook (CGAAP), have been adjusted as necessary to be compliant with the Company's policies under U.S. GAAP, which is discussed further in the Changes in Accounting Policies section in this MD&A. This MD&A should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TransCanada's 2011 Annual Report, as prepared in accordance with CGAAP, for the year ended December 31, 2011. Additional information relating to TransCanada, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada Corporation's profile. "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries, unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms used but not otherwise defined in this MD&A are identified in the Glossary of Terms contained in TransCanada's 2011 Annual Report.

Forward-Looking Information

This MD&A contains certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "will", "should", "estimate", "project", "outlook", "forecast", "intend", "target", "plan" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

- anticipated business prospects;
- financial performance of TransCanada and its subsidiaries and affiliates;
- expectations or projections about strategies and goals for growth and expansion;
- expected cash flows;
- expected costs;
- expected costs for projects under construction;
- expected schedules for planned projects (including anticipated construction and completion dates);
- expected regulatory processes and outcomes;
- expected outcomes with respect to legal proceedings, including arbitration;
- expected capital expenditures;
- expected operating and financial results; and

- expected impact of future commitments and contingent liabilities.

These forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TransCanada's actual results and achievements to differ materially from the anticipated results or expectations expressed or implied in such statements.

Key assumptions on which TransCanada's forward-looking statements are based include, but are not limited to, assumptions about:

- inflation rates, commodity prices and capacity prices;
- timing of debt issuances and hedging;
- regulatory decisions and outcomes;
- arbitration decisions and outcomes;
- foreign exchange rates;
- interest rates;
- tax rates;
- planned and unplanned outages and utilization of the Company's pipeline and energy assets;
- asset reliability and integrity;
- access to capital markets;
- anticipated construction costs, schedules and completion dates; and
- acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to:

- the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits;
- the operating performance of the Company's pipeline and energy assets;
- the availability and price of energy commodities;
- amount of capacity payments and revenues from the Company's energy business;
- regulatory decisions and outcomes;
- outcomes with respect to legal proceedings, including arbitration;
- counterparty performance;
- changes in environmental and other laws and regulations;
- competitive factors in the pipeline and energy sectors;
- construction and completion of capital projects;
- labour, equipment and material costs;
- access to capital markets;
- interest and currency exchange rates;
- weather;
- technological developments; and
- economic conditions in North America.

Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC).

Readers are cautioned against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise stated, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to publicly update or revise any forward-looking information in this MD&A or otherwise stated, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Measures

TransCanada uses the measures Comparable Earnings, Comparable Earnings per Share, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), Comparable EBITDA, Earnings Before Interest and Taxes (EBIT), Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning as prescribed by U.S. GAAP. They are, therefore, considered to be non-GAAP measures and are unlikely to be comparable to similar measures presented by other entities. Management of TransCanada uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends. EBITDA includes income from equity investments. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends. EBIT includes income from equity investments.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, and Comparable Income Taxes comprise Net Income Applicable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other, and Income Taxes, respectively, and are adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating these non-GAAP measures, some of which may recur. Specific items may include but are not limited to certain fair value adjustments relating to risk management activities, income tax adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments. These non-GAAP measures are calculated on a consistent basis from period to period. The specific items for which such measures are adjusted in each applicable period may only be relevant in certain periods and are disclosed in the Reconciliation of Non-GAAP Measures table in this MD&A.

The Company engages in risk management activities to reduce its exposure to certain financial and commodity price risks by utilizing derivatives. The risk management activities which TransCanada excludes from Comparable Earnings provide effective economic hedges but do not meet the specific criteria for hedge accounting treatment and, therefore, changes in their fair values are recorded in Net Income each year. The unrealized gains or losses from changes in the fair value of these derivative contracts are not considered to be representative of the underlying operations in the current period or the positive margin that will be realized upon settlement. As a result, these amounts have been excluded in the determination of Comparable Earnings.

The Reconciliation of Non-GAAP Measures table in this MD&A presents a reconciliation of these non-GAAP measures to Net Income Attributable to Common Shares. Comparable Earnings per Common Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the year.

Funds Generated from Operations comprise Net Cash Provided by Operations before changes in operating working capital and allows management to better measure consolidated operating cash flow, excluding fluctuations from working capital balances which may not necessarily be reflective of underlying operations in the same period. A reconciliation of Funds Generated from Operations to Net Cash Provided by Operations is presented in the Summarized Cash Flow table in the Liquidity and Capital Resources section in this MD&A.

Reconciliation of Non-GAAP Measures

Three months ended March 31 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2012	2011	Oil Pipelines 2012	2011	Energy 2012	2011	Corporate 2012	2011	Total 2012	2011
Comparable EBITDA	**725**	773	**173**	99	**244**	315	**(29)**	(24)	**1,113**	1,163
Depreciation and amortization	**(232)**	(228)	**(36)**	(23)	**(73)**	(67)	**(3)**	(3)	**(344)**	(321)
Comparable EBIT	**493**	545	**137**	76	**171**	248	**(32)**	(27)	**769**	842
Other Income Statement Items										
Comparable interest expense									**(242)**	(210)
Comparable interest income and other									**25**	28
Comparable income taxes									**(140)**	(187)
Net income attributable to non-controlling interests									**(35)**	(36)
Preferred share dividends									**(14)**	(14)
Comparable Earnings									**363**	423
Specific item (net of tax):										
Risk management activities[(1)]									**(11)**	(12)
Net Income Attributable to Common Shares									**352**	411

Three months ended March 31 *(unaudited) (millions of dollars)*	2012	2011
Comparable Interest Expense	**(242)**	(210)
Specific item:		
Risk management activities[(1)]	**-**	(1)
Interest Expense	**(242)**	(211)
Comparable Interest Income and Other	**25**	28
Specific item:		
Risk management activities[(1)]	**6**	2
Interest Income and Other	**31**	30
Comparable Income Taxes	**(140)**	(187)
Specific item:		
Income taxes attributable to risk management activities[(1)]	**11**	7
Income Taxes Expense	**(129)**	(180)
Comparable Earnings per Common Share	**$0.52**	$0.61
Specific item (net of tax):		
Risk management activities	**(0.02)**	(0.02)
Net Income per Share	**$0.50**	$0.59

(1)

Three months ended March 31 *(unaudited)(millions of dollars)*	2012	2011
Risk Management Activities Gains/(Losses):		
Canadian Power	**(2)**	-
U.S. Power	**(32)**	(13)
Natural Gas Storage	**6**	(7)
Interest rate	**-**	(1)
Foreign exchange	**6**	2
Income taxes attributable to risk management activities	**11**	7
Risk Management Activities	**(11)**	(12)

Consolidated Results of Operations

First Quarter Results

Comparable Earnings in first quarter 2012 were $363 million or $0.52 per share compared to $423 million or $0.61 per share for the same period in 2011. Comparable Earnings in first quarter 2012 excluded net unrealized after-tax losses of $11 million ($22 million pre-tax) (2011 – losses of $12 million after tax ($19 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings decreased $60 million or $0.09 per share in first quarter 2012 compared to the same period in 2011 and reflected the following:

- decreased Canadian Natural Gas Pipelines Comparable net income primarily due to lower earnings from the Canadian Mainline which exclude incentive earnings and reflect a lower investment base;
- decreased U.S. and International Natural Gas Pipelines EBIT which reflects lower revenue resulting from uncontracted capacity on Great Lakes and lower earnings from ANR, partially offset by incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011;
- increased Oil Pipelines Comparable EBIT as the Company commenced recording earnings from the Keystone Pipeline System in February 2011 and higher fixed tolls for the Wood River/Patoka section of the system;
- decreased Energy Comparable EBIT primarily due to a decrease in Equity Income from Bruce Power due to lower volumes resulting from increased planned outage days, lower realized power prices in U.S. Power and lower Natural Gas Storage revenue, partially offset by higher contributions from Western Power and Eastern Power;
- decreased Comparable Interest Income and Other due to lower realized gains in 2012 compared to 2011 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income; and
- decreased Comparable Income Taxes primarily due to lower pre-tax earnings in 2012 compared to 2011.

U.S. Dollar-Denominated Balances

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is partially offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in Canadian-U.S. foreign exchange rates. The average exchange rate to convert a U.S. dollar to a Canadian dollar for the three months ended March 31, 2012 was 1.00 (2011 – 0.99).

Summary of Significant U.S. Dollar-Denominated Amounts

Three months ended March 31 *(unaudited)(millions of U.S. dollars)*	**2012**	2011
U.S. Natural Gas Pipelines Comparable EBIT[1]	215	243
U.S. Oil Pipelines Comparable EBIT[1]	89	51
U.S. Power Comparable EBIT[1]	6	32
Interest on U.S. dollar-denominated long-term debt	(186)	(182)
Capitalized interest on U.S. capital expenditures	26	47
U.S. non-controlling interests and other	(51)	(51)
	99	140

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBIT.

Natural Gas Pipelines

Natural Gas Pipelines' Comparable EBIT was $493 million in first quarter 2012 compared to $545 million for the same period in 2011.

Natural Gas Pipelines Results

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Canadian Natural Gas Pipelines		
Canadian Mainline	**250**	265
Alberta System	**177**	185
Foothills	**31**	33
Other (TQM[(1)], Ventures LP)	**8**	8
Canadian Natural Gas Pipelines Comparable EBITDA[(2)]	**466**	491
Depreciation and amortization[(3)]	**(177)**	(178)
Canadian Natural Gas Pipelines Comparable EBIT[(2)]	**289**	313
U.S. and International Natural Gas Pipelines (in U.S. dollars)		
ANR	**97**	109
GTN[(4)]	**30**	45
Great Lakes[(5)]	**18**	30
TC PipeLines, LP[(1)(6)(7)]	**20**	23
Other U.S. Pipelines (Iroquois[(1)], Bison[(8)], Portland[(7)(9)])	**34**	36
International (Tamazunchale, Guadalajara[(10)], TransGas[(1)], Gas Pacifico/INNERGY[(1)])	**28**	10
General, administrative and support costs[(11)]	**(2)**	(2)
Non-controlling interests[(7)]	**45**	43
U.S. and International Natural Gas Pipelines Comparable EBITDA[(2)]	**270**	294
Depreciation and amortization[(3)]	**(55)**	(51)
U.S. and International Natural Gas Pipelines Comparable EBIT[(2)]	**215**	243
Foreign exchange	**-**	(3)
U.S. and International Natural Gas Pipelines Comparable EBIT[(2)] (in Canadian dollars)	**215**	240
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT[(2)]	**(11)**	(8)
Natural Gas Pipelines Comparable EBIT[(2)]	**493**	545
Summary:		
Natural Gas Pipelines Comparable EBITDA[(2)]	**725**	773
Depreciation and amortization[(3)]	**(232)**	(228)
Natural Gas Pipelines Comparable EBIT[(2)]	**493**	545

(1) Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect the Company's share of equity income from these investments.
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(3) Does not include depreciation and amortization from equity investments.
(4) Results reflect TransCanada's direct ownership interest of 75 per cent effective May 2011 and 100 per cent prior to that date.
(5) Represents TransCanada's 53.6 per cent direct ownership interest.

(6) Effective May 2011, TransCanada's ownership interest in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent. As a result, the TC PipeLines, LP results include TransCanada's decreased ownership in TC PipeLines, LP and TransCanada's effective ownership through TC PipeLines, LP of 8.3 per cent of each of GTN and Bison since May 2011.
(7) Non-Controlling Interests reflects Comparable EBITDA for the portions of TC PipeLines, LP and Portland not owned by TransCanada.
(8) Results reflect TransCanada's direct ownership of 75 per cent of Bison effective May 2011 when 25 per cent was sold to TC PipeLines, LP and 100 per cent since January 2011 when Bison went into service.
(9) Includes TransCanada's 61.7 per cent ownership interest.
(10) Includes Guadalajara's operations since June 2011.
(11) Represents General, Administrative and Support Costs associated with certain of TransCanada's pipelines.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

Three months ended March 31 *(millions of dollars)*	**2012**	2011
Canadian Mainline	**47**	62
Alberta System	**48**	48
Foothills	**5**	6

Canadian Natural Gas Pipelines

Canadian Mainline's net income of $47 million in first quarter 2012 decreased $15 million from $62 million in the same period in 2011. Canadian Mainline's first quarter 2011 net income included incentive earnings earned under an incentive arrangement included as part of the five-year tolls settlement which expired December 31, 2011. Absent a National Energy Board (NEB) decision with respect to 2012 tolls, Canadian Mainline's first quarter 2012 results reflect the last approved rate of return on common equity of 8.08 per cent on deemed common equity of 40 per cent and exclude incentive earnings. Canadian Mainline's first quarter 2012 results also reflect a lower investment base compared to first quarter 2011.

The Alberta System's net income of $48 million in first quarter 2012 was equal to that of 2011. The positive impact on 2012 net income from a higher average investment base was offset by lower incentive earnings.

Canadian Mainline's Comparable EBITDA for first quarter 2012 of $250 million decreased $15 million compared to the same period in 2011. The Alberta System's Comparable EBITDA was $177 million in first quarter 2012 compared to $185 million in the same period in 2011. EBITDA from the Canadian Mainline and the Alberta System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis.

U.S. Natural Gas Pipelines

ANR's Comparable EBITDA in first quarter 2012 was US$97 million compared to US$109 million for the same period in 2011. The decrease was primarily due to higher operating, maintenance and administration (OM&A) costs, lower incidental commodity sales and lower transportation revenues.

GTN's Comparable EBITDA in first quarter 2012 was US$30 million compared to US$45 million for the same period in 2011. The decrease was primarily due to TransCanada's sale of a 25 per cent interest in GTN to TC PipeLines, LP in May 2011 as well as lower contracted transportation revenues.

Great Lakes' Comparable EBITDA in first quarter 2012 was US$18 million compared to US$30 million for the same period in 2011. The decrease was due to lower transportation revenues resulting from uncontracted capacity.

International Comparable EBITDA in first quarter 2012 was US$28 million compared to US$10 million for the same period in 2011 primarily due to incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011.

Operating Statistics

Three months ended March 31 *(unaudited)*	Canadian Mainline(1) 2012	2011	Alberta System(2) 2012	2011	ANR(3) 2012	2011
Average investment base (millions of dollars)	**5,812**	6,404	**5,282**	4,966	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**430**	597	**998**	1,000	**482**	480
Average per day	**4.7**	6.6	**11.0**	11.1	**5.3**	5.3

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the three months ended March 31, 2012 were 247 billion cubic feet (Bcf) (2011 – 376 Bcf); average per day was 2.7 Bcf (2011 – 4.2 Bcf).

(2) Field receipt volumes for the Alberta System for the three months ended March 31, 2012 were 948 Bcf (2011 – 843 Bcf); average per day was 10.4 Bcf (2011 – 9.4 Bcf).

(3) Under its current rates, which are approved by the FERC, ANR's results are not impacted by changes in its average investment base.

Oil Pipelines

Oil Pipelines Comparable EBIT for first quarter 2012 was $137 million compared to $76 million for the same period in 2011.

Oil Pipelines Results

(unaudited)(millions of dollars)	**Three months ended March 31, 2012**	Two months ended March 31, 2011
Keystone Pipeline System	**174**	99
Oil Pipeline Business Development	**(1)**	-
Oil Pipelines Comparable EBITDA(1)	**173**	99
Depreciation and amortization	**(36)**	(23)
Oil Pipelines Comparable EBIT(1)	**137**	76
Comparable EBIT denominated as follows:		
Canadian dollars	**48**	26
U.S. dollars	**89**	51
Foreign exchange	**-**	(1)
Oil Pipelines Comparable EBIT(1)	**137**	76

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

Keystone Pipeline System

The Keystone Pipeline System's Comparable EBITDA in first quarter 2012 was $174 million compared to $99 million for the same period in 2011. The increase was primarily due to the impact of three months of earnings being recorded for the Wood River/Patoka and Cushing Extension sections of the Keystone Pipeline System compared to only two months in first quarter 2011, as well as the incremental impact of higher fixed tolls which came into effect in May 2011 on the Wood River/Patoka section of the system.

EBITDA from the Keystone Pipeline System is primarily generated from payments received under long-term commercial arrangements for committed capacity that are not dependant on actual throughput. Uncontracted capacity is offered to the market on a spot basis and, when capacity is available, provides opportunities to generate incremental EBITDA.

Depreciation and Amortization
Oil Pipelines depreciation and amortization increased $13 million in first quarter 2012 compared to the same period in 2011 reflecting three months of operations compared to two months in 2011 for the Wood River/Patoka and Cushing Extension sections of the Keystone Pipeline System.

Operating Statistics

(unaudited)	**Three months ended March 31, 2012**	Two months ended March 31, 2011
Delivery volumes (thousands of barrels)[1]		
Total	**48,764**	22,466
Average per day	**536**	381

(1) Delivery volumes reflect physical deliveries.

Energy

Energy's Comparable EBIT was $171 million in first quarter 2012 compared to $248 million for the same period in 2011.

Energy Results

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Canadian Power		
Western Power[(1)(2)]	**131**	119
Eastern Power[(1)(3)]	**93**	76
Bruce Power[(1)]	**(13)**	43
General, administrative and support costs	**(11)**	(8)
Canadian Power Comparable EBITDA[(4)]	**200**	230
Depreciation and amortization[(5)]	**(40)**	(34)
Canadian Power Comparable EBIT[(4)]	**160**	196
U.S. Power (in U.S. dollars)		
Northeast Power	**46**	71
General, administrative and support costs	**(10)**	(9)
U.S. Power Comparable EBITDA[(4)]	**36**	62
Depreciation and amortization	**(30)**	(30)
U.S. Power Comparable EBIT[(4)]	**6**	32
Foreign exchange	**-**	-
U.S. Power Comparable EBIT[(4)] (in Canadian dollars)	**6**	32
Natural Gas Storage		
Alberta Storage[(1)]	**15**	30
General, administrative and support costs	**(2)**	(2)
Natural Gas Storage Comparable EBITDA[(4)]	**13**	28
Depreciation and amortization[(5)]	**(3)**	(3)
Natural Gas Storage Comparable EBIT[(4)]	**10**	25
Energy Business Development Comparable EBITDA and EBIT[(1)(4)]	**(5)**	(5)
Energy Comparable EBIT[(1)(4)]	**171**	248
Summary:		
Energy Comparable EBITDA[(4)]	**244**	315
Depreciation and amortization[(5)]	**(73)**	(67)
Energy Comparable EBIT[(4)]	**171**	248

(1) Results from ASTC Power Partnership, Portlands Energy, Bruce Power and CrossAlta reflect the Company's share of equity income from these investments.
(2) Includes Coolidge effective May 2011.
(3) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011.
(4) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(5) Does not include depreciation and amortization of equity investments.

Canadian Power

Western and Eastern Canadian Power Comparable EBIT[(1)(2)(3)]

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Revenue		
Western power[(2)]	**224**	221
Eastern power[(3)]	**103**	96
Other[(4)]	**25**	23
	352	340
Income from Equity Investments[(5)]	**23**	27
Commodity Purchases Resold		
Western power	**(94)**	(104)
Other[(6)]	**(2)**	(5)
	(96)	(109)
Plant operating costs and other	**(55)**	(63)
General, administrative and support costs	**(11)**	(8)
Comparable EBITDA[(1)]	**213**	187
Depreciation and amortization	**(40)**	(34)
Comparable EBIT[(1)]	**173**	153

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes Coolidge effective May 2011. Includes the net realized gains and losses from derivatives used to purchase and sell power.
(3) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011.
(4) Includes sales of excess natural gas purchased for generation and thermal carbon black. Includes the net realized gains and losses from derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets.
(5) Results reflect equity income from TransCanada's 50 per cent ownership interest in each of ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.
(6) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics[(1)]

Three months ended March 31 *(unaudited)*	**2012**	2011
Volumes (GWh)		
Generation		
Western Power[(2)]	**671**	681
Eastern Power[(3)]	**1,143**	1,078
Purchased		
Sundance A and B and Sheerness PPAs[(4)]	**2,039**	2,105
Other purchases	**45**	88
	3,898	3,952
Contracted		
Western Power[(2)]	**2,295**	2,155
Eastern Power[(3)]	**1,143**	1,078
Spot		
Western Power	**460**	719
	3,898	3,952
Plant Availability[(5)]		
Western Power[(2)(6)]	**99%**	98%
Eastern Power[(3)(7)]	**93%**	99%

(1) Includes TransCanada's share of Equity Investments' volumes.
(2) Includes Coolidge effective May 2011.
(3) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011 and volumes related to TransCanada's 50 per cent ownership interest in Portlands Energy.
(4) Includes TransCanada's 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. No volumes were delivered under the Sundance A PPA in 2012 or 2011.
(5) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(6) Excludes facilities that provide power under PPAs.
(7) Bécancour has been excluded from the availability calculation as power generation has been suspended since 2008.

Western Power's Comparable EBITDA of $131 million and Power Revenues of $224 million in first quarter 2012 increased $12 million and $3 million, respectively, compared to the same period in 2011, primarily due to incremental earnings from Coolidge, which was placed in service in May 2011, and higher realized power prices, partially offset by a decrease in Sundance A power purchase arrangement (PPA) earnings.

Western Power's Comparable EBITDA in first quarter 2012 included $30 million (2011 - $39 million) of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 are interruptions of supply in accordance with the terms of the PPA. The decrease of $9 million in Sundance A earnings in first quarter 2012 compared to first quarter 2011 is a result of lower Alberta spot power prices in 2012. Average spot market power prices in Alberta decreased 28 per cent to $60 per megawatt hour (MWh) in first quarter 2012 compared to $83 per MWh in first quarter 2011 when unseasonably cold weather combined with unplanned plant outages caused an increase in demand and reduction in market supply. Despite the decrease in spot prices, Western Power earned a higher realized price compared to the prior period as a result of hedging activities. Refer to the Recent Developments section in this MD&A for further discussion regarding the Sundance A outage.

Eastern Power's Comparable EBITDA of $93 million and Power Revenues of $103 million in first quarter 2012 increased $17 million and $7 million, respectively, compared to the same period in 2011. The increases were primarily due to higher Bécancour contractual earnings and incremental earnings from Montagne-Sèche and phase one of Gros-Morne, which was placed in service in November 2011.

Plant Operating Costs and Other, which includes fuel gas consumed in power generation, of $55 million in first quarter 2012, decreased $8 million compared to the same period in 2011, primarily due to decreased natural gas fuel prices in first quarter 2012 compared to the same period in 2011.

Depreciation and amortization increased $6 million in first quarter 2012 compared to the same period in 2011 primarily due to incremental depreciation from Coolidge, Montagne-Sèche and phase one of Gros-Morne.

Approximately 83 per cent of Western Power sales volumes were sold under contract in first quarter 2012, compared to 75 per cent in first quarter 2011. To reduce its exposure to spot market prices in Alberta, as at March 31, 2012, Western Power had entered into fixed-price power sales contracts to sell approximately 6,000 gigawatt hours (GWh) for the remainder of 2012 and 6,300 GWh for 2013.

Eastern Power's sales volumes were 100 per cent sold under contract and are expected to be fully contracted going forward.

Bruce Power Results

(TransCanada's share) Three months ended March 31 *(unaudited)(millions of dollars unless otherwise indicated)*	**2012**	2011
Income from Equity Investments[1]		
Bruce A	**(33)**	18
Bruce B	**20**	25
	(13)	43
Comprised of:		
Revenues	**162**	213
Operating expenses	**(135)**	(136)
Depreciation and other	**(40)**	(34)
	(13)	43
Bruce Power – Other Information		
Plant availability[2]		
Bruce A	**48%**	100%
Bruce B	**86%**	91%
Combined Bruce Power	**62%**	94%
Planned outage days		
Bruce A	**91**	-
Bruce B	**46**	21
Unplanned outage days		
Bruce A	**-**	4
Bruce B	**4**	8
Sales volumes (GWh)[1]		
Bruce A	**747**	1,500
Bruce B	**1,909**	2,032
	2,656	3,532
Realized sales price per MWh		
Bruce A	**$66**	$65
Bruce B[3]	**$54**	$53
Combined Bruce Power	**$57**	$57

(1) Represents TransCanada's 48.8 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.
(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.
(3) Includes revenue received under the floor price mechanism and from contract settlements as well as volumes and revenues associated with deemed generation.

TransCanada's Equity Income from Bruce A decreased $51 million in first quarter 2012 to a loss of $33 million compared to income of $18 million in first quarter 2011 primarily due to lower volumes resulting from the West Shift Plus planned outage on Unit 3 which took place throughout the quarter and is expected to be completed in second quarter 2012.

TransCanada's Equity Income from Bruce B decreased $5 million in first quarter 2012 to $20 million compared to $25 million in first quarter 2011 primarily due to lower volumes resulting from higher planned outage days.

Under a contract with the Ontario Power Authority (OPA), all output from Bruce A in first quarter 2012 was sold at a fixed price of $66.33 per MWh (before recovery of fuel costs from the OPA) compared to $64.71 per MWh in first quarter 2011. Also under a contract with the OPA, all output from the Bruce B units was subject to a floor price of $50.18 per MWh in first quarter 2012 compared to $48.96 per MWh in first quarter 2011. Effective April 1, 2012, the fixed price for output from Bruce A increased to $68.23 per MWh and the Bruce B floor price increased to $51.62 per MWh.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. With respect to 2012, TransCanada currently expects spot prices to be less than the floor price for the year, therefore no amounts recorded in revenues in first quarter 2012 are expected to be repaid.

Bruce B enters into fixed-price contracts whereby Bruce B receives or pays the difference between the contract price and the spot price. Bruce B's realized price increased by $1 per MWh to $54 per MWh in first quarter 2012 compared to the same period in 2011 and reflected revenues recognized from the floor price mechanism, contract sales and deemed generation.

The overall plant availability percentage in 2012 is expected to be in the low 70s for Bruce A Units 3 and 4. The Bruce A West Shift Plus outage, which commenced in November 2011, is expected to be completed in second quarter 2012. Additional planned maintenance on one of the units at Bruce A is scheduled for the summer of 2012. Bruce B's overall plant availability percentage is expected to be in the mid 90s for the four units in 2012.

U.S. Power

U.S. Power Comparable EBIT(1)

Three months ended March 31 *(unaudited)(millions of U.S. dollars)*	**2012**	2011
Revenues		
Power(2)	**161**	255
Capacity	**40**	39
Other(3)	**19**	30
	220	324
Commodity purchases resold	**(83)**	(131)
Plant operating costs and other(3)	**(91)**	(122)
General, administrative and support costs	**(10)**	(9)
Comparable EBITDA(1)	**36**	62
Depreciation and amortization	**(30)**	(30)
Comparable EBIT(1)	**6**	32

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) The realized gains and losses from financial derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in Power Revenues.
(3) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics

Three months ended March 31 *(unaudited)*	**2012**	2011
Physical Sales Volumes (GWh)		
Supply		
Generation	**1,154**	1,291
Purchased	**1,954**	1,939
	3,108	3,230
Plant Availability(1)	**80%**	82%

(1) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.

U.S Power's Comparable EBITDA of US$36 million and Power Revenues of US$161 million decreased US$26 million and US$94 million, respectively, compared to the same period in 2011. The reduction was primarily due to lower realized power prices which were negatively impacted by lower natural gas prices.

Capacity Revenue of US$40 million in first quarter 2012 increased US$1 million compared to the same period in 2011. Capacity Revenues in first quarter 2012 were positively impacted by higher capacity prices in New York while New England capacity prices decreased slightly compared to 2011.

Commodity Purchases Resold of US$83 million decreased US$48 million compared to the same period in 2011 primarily due to lower realized prices on power purchased for resale under power sales commitments to wholesale, commercial and industrial customers.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of US$91 million decreased US$31 million primarily due to lower natural gas fuel prices.

As at March 31, 2012, approximately 3,000 GWh or 35 per cent and 2,500 GWh or 30 per cent of U.S. Power's planned generation is contracted for the remainder 2012 and fiscal 2013, respectively. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA in first quarter 2012 declined to $13 million compared to $28 million for the same period in 2011 primarily due to lower realized natural gas price spreads.

Other Income Statement Items

Comparable Interest Expense[(1)]

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Interest on long-term debt[(2)]		
Canadian dollar-denominated	**128**	122
U.S. dollar-denominated	**186**	182
Foreign exchange	**-**	(3)
	314	301
Other interest and amortization	**2**	6
Capitalized interest	**(74)**	(97)
Comparable Interest Expense[(1)]	**242**	210

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable Interest Expense.
(2) Includes interest on Junior Subordinated Notes.

Comparable Interest Expense in first quarter 2012 increased $32 million to $242 million compared to $210 million in first quarter 2011. The increase was primarily due to lower capitalized interest for Keystone and Coolidge as a result of placing these assets in service, incremental interest expense on debt issues of US$500 million in March 2012, $750 million in November 2011 and US$350 million in July 2011. These increases were partially offset by the impact of Canadian and U.S. dollar-denominated debt maturities in 2012 and 2011.

Comparable Interest Income and Other for first quarter 2012 decreased $3 million to $25 million compared to $28 million in first quarter 2011, primarily due to lower realized gains in 2012 compared to 2011 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable Income Taxes were $140 million in first quarter 2012 compared to $187 million for the same period in 2011. The decrease was primarily due to lower pre-tax earnings in 2012 compared to 2011.

Liquidity and Capital Resources

TransCanada believes that its financial position remains sound as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and provide for planned growth. TransCanada's liquidity is underpinned by predictable cash flow from operations, available cash balances and unutilized committed revolving bank lines of US$1.0 billion, US$1.0 billion, US$300 million and $2.0 billion, maturing in October 2012, November 2012, February 2013 and October 2016, respectively. These facilities also support the Company's three commercial paper programs. In addition, at March 31, 2012, TransCanada's proportionate share of unutilized capacity on committed bank facilities at TransCanada operated affiliates was $84 million with maturity dates in 2016. As at March 31, 2012, TransCanada had remaining capacity of $2.0 billion, $1.25 billion and US$3.5 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

Operating Activities

Funds Generated from Operations[(1)]

Three months ended March 31 *(unaudited)(millions of dollars)*	**2012**	2011
Cash Flows		
Funds generated from operations[(1)]	**841**	815
(Increase)/decrease in operating working capital	**(169)**	19
Net cash provided by operations	**672**	834

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Funds Generated from Operations.

Net Cash Provided by Operations decreased $162 million in the first quarter of 2012, compared to the same period in 2011, largely as a result of changes in operating working capital partially offset by increased Funds Generated from Operations. Funds Generated from Operations for the first quarter 2012 were $841 million compared to $815 million for the same period in 2011.

As at March 31, 2012, TransCanada's current assets were $2.7 billion and current liabilities were $4.7 billion resulting in a working capital deficiency of $2.0 billion. The Company believes this shortfall can be managed through its ability to generate cash flow from operations as well as its ongoing access to capital markets.

Investing Activities

In first quarter 2012, capital expenditures totalled $464 million (2011– $567 million), primarily related to the expansion of the Keystone Pipeline System and expansion of the Alberta System. Equity investments of $216 million (2011 - $151 million) primarily related to the Company's investment in the refurbishment and restart of Bruce Power Units 1 and 2.

Financing Activities

In March 2012, TransCanada PipeLines Limited (TCPL) issued US$500 million of Senior Notes maturing on March 2, 2015 and bearing interest at an annual rate of 0.875 per cent. These notes were issued under the US$4.0 billion debt shelf prospectus filed in November 2011. The net proceeds of this offering were used for general corporate purposes and to reduce short-term indebtedness.

In January 2012, TransCanada PipeLine USA Ltd. repaid the remaining principal of US$500 million on its five-year term loan.

The Company believes it has the capacity to fund its existing capital program through internally-generated cash flow, continued access to capital markets and liquidity underpinned by in excess of $4 billion of committed credit facilities. TransCanada's financial flexibility is further bolstered by opportunities for portfolio management, including an ongoing role for TC PipeLines, LP.

Dividends

On April 26, 2012, TransCanada's Board of Directors declared a quarterly dividend of $0.44 per share for the quarter ending June 30, 2012 on the Company's outstanding common shares. The dividend is payable on July 31, 2012 to shareholders of record at the close of business on June 29, 2012. In addition, quarterly dividends of $0.2875 and $0.25 per Series 1 and Series 3 preferred share, respectively, were declared for the quarter ending June 30, 2012. The dividends are payable on June 29, 2012 to shareholders of record at the close of business on May 31, 2012. Furthermore, a quarterly dividend of $0.275 per Series 5 preferred share was declared for the period ending July 30, 2012, payable on July 30, 2012 to shareholders of record at the close of business on June 30, 2012.

Contractual Obligations

There have been no material changes to TransCanada's contractual obligations from December 31, 2011 to March 31, 2012, including payments due for the next five years and thereafter. For further information on these contractual obligations, refer to the MD&A in TransCanada's 2011 Annual Report.

Significant Accounting Policies and Critical Accounting Estimates

The condensed consolidated financial statements of TransCanada have been prepared by management in accordance with U.S. GAAP. Comparative figures, which were previously presented in accordance with CGAAP, have been adjusted as necessary to be compliant with the Company's policies under U.S. GAAP. The amounts adjusted for U.S. GAAP in these condensed consolidated financial statements for the three months ended March 31, 2011 are the same as those that have been previously reported in the Company's March 31, 2011 Reconciliation to U.S. GAAP. The amounts adjusted for U.S. GAAP at December 31, 2011 are the same as those reported in Note 25 of TransCanada's 2011 audited Consolidated Financial Statements included in TransCanada's 2011 Annual Report. The significant accounting policies and critical accounting estimates applied are consistent with those outlined in TransCanada's 2011 Annual Report, except as described below, which outlines the Company's significant accounting policies that have changed upon adoption of U.S. GAAP.

To prepare financial statements that conform with U.S. GAAP, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions.

Changes in Accounting Policies

Changes to Significant Accounting Policies Upon Adoption of U.S. GAAP

Principles of Consolidation
The condensed consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TransCanada uses the equity method of accounting for corporate joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TransCanada records its proportionate share of undivided interests in certain assets.

Inventories
Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are recorded at the lower of weighted average cost or market.

Income Taxes
The Company uses the liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Employee Benefit and Other Plans
The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans' as an asset or liability on its Balance Sheet and recognizes changes in that funded status through Other Comprehensive (Loss)/Income (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated Other Comprehensive (Loss)/Income (AOCI) over the average remaining service period of the active employees. For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains and losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the average remaining service life of active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Long-Term Debt Transaction Costs
Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company records long-term debt transaction costs as deferred assets and amortizes these costs using the effective interest method for all costs except those related to the

Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

Guarantees
Upon issuance, the Company records the fair value of certain guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to Equity Investments, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Changes in Accounting Policies for 2012

Fair Value Measurement
Effective January 1, 2012, the Company adopted the Accounting Standards Update (ASU) on fair value measurements as issued by the Financial Accounting Standards Board (FASB). Adoption of the ASU has resulted in an increase in the qualitative and quantitative disclosures regarding Level III measurements.

Intangibles – Goodwill and Other
Effective January 1, 2012, the Company adopted the ASU on testing goodwill for impairment as issued by the FASB. Adoption of the ASU has resulted in a change in the accounting policy related to testing goodwill for impairment, as the Company is now permitted under U.S. GAAP to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount as a basis for determining whether it is required to proceed to the two-step quantitative impairment test.

Future Accounting Changes

Balance Sheet Offsetting/Netting
In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting arrangement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosure regarding financial instruments which are subject to offsetting as described in this amendment.

Financial Instruments and Risk Management

TransCanada continues to manage and monitor its exposure to market risk, counterparty credit risk and liquidity risk.

Counterparty Credit and Liquidity Risk
TransCanada's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, the fair value of derivative assets, and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with

counterparties who are investment grade. At March 31, 2012, there were no significant amounts past due or impaired.

At March 31, 2012, the Company had a credit risk concentration of $267 million due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

The Company continues to manage its liquidity risk by ensuring sufficient cash and credit facilities are available to meet its operating and capital expenditure obligations when due, under both normal and stressed economic conditions.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At March 31, 2012, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10.4 billion (US$10.4 billion) and a fair value of $12.9 billion (US$12.9 billion). At March 31, 2012, $97 million (December 31, 2011 - $79 million) was included in Other Current Assets, $83 million (December 31, 2011 - $66 million) was included in Intangibles and Other Assets, $4 million (December 31, 2011 - $15 million) was included in Accounts Payable and $30 million (December 31, 2011 - $41 million) was included in Deferred Amounts for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

The fair values and notional principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**March 31, 2012** **Fair Value**[(1)]	**March 31, 2012** **Notional or Principal Amount**	December 31, 2011 Fair Value[(1)]	December 31, 2011 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2019)[(2)]	**128**	**US 4,150**	93	US 3,850
U.S. dollar forward foreign exchange contracts (maturing 2012)	**18**	**US 1,165**	(4)	US 725
	146	**US 5,315**	89	US 4,575

(1) Fair values equal carrying values.

(2) Consolidated Net Income in first quarter 2012 included net realized gains of $7 million (2011 – gains of $5 million) related to the interest component of cross-currency swap settlements.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

(unaudited) (millions of dollars)	March 31, 2012 Carrying Amount(1)	March 31, 2012 Fair Value(2)	December 31, 2011 Carrying Amount(1)	December 31, 2011 Fair Value(2)
Financial Assets				
Cash and cash equivalents	**196**	**196**	654	654
Accounts receivable and other(3)	**1,326**	**1,369**	1,359	1,403
Available-for-sale assets(3)	**34**	**34**	23	23
	1,556	**1,599**	2,036	2,080
Financial Liabilities(4)				
Notes payable	**1,787**	**1,787**	1,863	1,863
Accounts payable and deferred amounts(5)	**1,016**	**1,016**	1,329	1,329
Accrued interest	**360**	**360**	365	365
Long-term debt	**18,397**	**23,313**	18,659	23,757
Junior subordinated notes	**998**	**1,031**	1,016	1,027
	22,558	**27,507**	23,232	28,341

(1) Recorded at amortized cost, except for US$350 million (December 31, 2011 – US$350 million) of Long-Term Debt that is recorded at fair value. This debt which is recorded at fair value on a recurring basis is classified in Level II of the fair value category using the income approach based on interest rates from external data service providers.

(2) The fair value measurement of financial assets and liabilities recorded at amortized cost for which the fair value is not equal to the carrying value would be included in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.

(3) At March 31, 2012, the Condensed Consolidated Balance Sheet included financial assets of $1,068 million (December 31, 2011 – $1,094 million) in Accounts Receivable, $33 million (December 31, 2011 – $41 million) in Other Current Assets and $259 million (December 31, 2011 - $247 million) in Intangibles and Other Assets.

(4) Consolidated Net Income in first quarter 2012 included losses of $15 million (2011 – losses of $9 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2011 – US$350 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(5) At March 31, 2012, the Condensed Consolidated Balance Sheet included financial liabilities of $886 million (December 31, 2011 – $1,192 million) in Accounts Payable and $130 million (December 31, 2011 - $137 million) in Deferred Amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

March 31, 2012 *(unaudited)* *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$314**	**$189**	**$9**	**$19**
Liabilities	**$(329)**	**$(232)**	**$(13)**	**$(19)**
Notional Values				
Volumes[3]				
Purchases	**31,088**	**104**	**-**	**-**
Sales	**29,851**	**76**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**684**
U.S. dollars	**-**	**-**	**US 1,476**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized (losses)/gains in the three months ended March 31, 2012[4]	**$(7)**	**$(14)**	**$6**	**$-**
Net realized gains/(losses) in the three months ended March 31, 2012[4]	**$15**	**$(10)**	**$9**	**$-**
Maturity dates	**2012-2016**	**2012-2016**	**2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$40**	**$-**	**$-**	**$15**
Liabilities	**$(321)**	**$(23)**	**$(39)**	**$-**
Notional Values				
Volumes[3]				
Purchases	**21,455**	**6**	**-**	**-**
Sales	**8,704**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 42**	**US 350**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized (losses)/gains in the three months ended March 31, 2012[4]	**$(32)**	**$(6)**	**$-**	**$1**
Maturity dates	**2012-2017**	**2012-2013**	**2012-2014**	**2013-2015**

(1) All derivative financial instruments held for trading have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(4) Realized and unrealized gains and losses on derivative financial instruments held for trading used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in cash flow hedging relationships is initially recognized in Other Comprehensive Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $15 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three months ended March 31, 2012 were $2 million and were included in Interest Expense. In first quarter 2012, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three months ended March 31, 2012, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

2011

(unaudited) *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2][3]				
Assets	$185	$176	$3	$22
Liabilities	$(192)	$(212)	$(14)	$(22)
Notional Values[3]				
Volumes[4]				
Purchases	21,905	103	-	-
Sales	21,334	82	-	-
Canadian dollars	-	-	-	684
U.S. dollars	-	-	US 1,269	US 250
Cross-currency	-	-	47/US 37	-
Net unrealized (losses)/gains in the three months ended March 31, 2011[5]	$(1)	$(16)	$2	$(1)
Net realized (losses)/gains in the three months ended March 31, 2011[5]	$(1)	$(26)	$21	$1
Maturity dates	2012-2016	2012-2016	2012	2012-2016
Derivative Financial Instruments in Hedging Relationships[6][7]				
Fair Values[2][3]				
Assets	$16	$3	$-	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional Values[3]				
Volumes[4]				
Purchases	17,188	8	-	-
Sales	8,061	-	-	-
U.S. dollars	-	-	US 73	US 600
Cross-currency	-	-	136/US 100	-
Net realized losses in the three months ended March 31, 2011[5]	$(43)	$(3)	$-	$(1)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

(1) All derivative financial instruments held for trading have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) As at December 31, 2011.

(4) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(5) Realized and unrealized gains and losses on derivative financial instruments held for trading used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in cash flow hedging relationships is initially recognized in Other Comprehensive Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(6) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million at December 31, 2011. Net realized gains on fair value hedges for the three months ended March 31, 2011 were $2 million and were included in Interest Expense. In first quarter 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(7) For the three months ended March 31, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts were excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

(unaudited) *(millions of dollars)*	**March 31 2012**	December 31 2011
Current		
Other current assets	**503**	361
Accounts payable	**(607)**	(485)
Long term		
Intangibles and other assets	**263**	202
Deferred amounts	**(403)**	(349)

Derivatives in Cash Flow Hedging Relationships

The components of OCI related to derivatives in cash flow hedging relationships are as follows:

	Cash Flow Hedges							
Three months ended March 31 *(unaudited)* *(millions of dollars, pre-tax)*	Power		Natural Gas		Foreign Exchange		Interest	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**(66)**	(55)	**(10)**	(11)	**(3)**	(6)	**-**	-
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**47**	34	**13**	28	**-**	-	**6**	9
Losses on derivative instruments recognized in earnings (ineffective portion)	**(6)**	(2)	**(2)**	(1)	**-**	-	**-**	-

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at March 31, 2012, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $110 million (2011 - $86 million), for which the Company had provided collateral of $53 million (2011 - $3 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on March 31, 2012, the Company would have been required to provide additional collateral of $57 million (2011 - $83 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's assets and liabilities recorded at fair value have been classified into three categories based on the fair value hierarchy.

In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.

In Level II, the fair value of interest rate and foreign exchange derivative assets and liabilities is determined using the income approach. The fair value of power and gas commodity assets and liabilities is determined using the market approach. Under both approaches, valuation is based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Such inputs include published exchange rates, interest rates, interest rate swap curves, yield curves, and broker quotes from external data service providers. Transfers between Level I and Level II would occur when there is a change in market circumstances. There were no transfers between Level I and Level II in first quarter 2012 and 2011.

In Level III, the fair value of assets and liabilities measured on a recurring basis is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II. There were no transfers between Level II and Level III in first quarter 2012 and 2011.

Long-dated commodity transactions in certain markets where liquidity is low are included in Level III of the fair value hierarchy, as the related commodity prices are not readily observable. Long-term electricity prices are estimated using a third-party modelling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Inputs into the model include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices are based on a view of future natural gas supply and demand, as well as exploration and development costs. Long-term prices are reviewed by management and the Board on a periodic basis. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas would result in a lower fair value measurement of contracts included in Level III.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions, are categorized as follows:

(unaudited) (millions of dollars, pre-tax)	Quoted Prices in Active Markets (Level I) Mar 31 2012	Dec 31 2011	Significant Other Observable Inputs (Level II) Mar 31 2012	Dec 31 2011	Significant Unobservable Inputs (Level III) Mar 31 2012	Dec 31 2011	Total Mar 31 2012	Dec 31 2011
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**34**	36	**-**	-	**34**	36
Foreign exchange contracts	**-**	-	**187**	141	**-**	-	**187**	141
Power commodity contracts	**-**	-	**337**	201	**-**	-	**337**	201
Gas commodity contracts	**136**	124	**50**	55	**-**	-	**186**	179
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(19)**	(23)	**-**	-	**(19)**	(23)
Foreign exchange contracts	**-**	-	**(84)**	(102)	**-**	-	**(84)**	(102)
Power commodity contracts	**-**	-	**(621)**	(454)	**(11)**	(15)	**(632)**	(469)
Gas commodity contacts	**(228)**	(208)	**(25)**	(26)	**-**	-	**(253)**	(234)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**34**	23	**-**	-	**-**	-	**34**	23
	(58)	(61)	**(141)**	(172)	**(11)**	(15)	**(210)**	(248)

The following table presents the net change in the Level III fair value category:

Three months ended March 31 *(unaudited) (millions of dollars, pre-tax)*	Derivatives[(1)(2)] 2012	2011
Balance at January 1	**(15)**	(8)
New contracts	**-**	1
Total gains or losses included in OCI	**4**	(6)
Balance at March 31	**(11)**	(13)

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) At March 31, 2012, there were no unrealized gains or losses included in Net Income attributable to derivatives that were still held at the reporting date (2011 – nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at March 31, 2012.

Other Risks

Additional risks faced by the Company are discussed in the MD&A in TransCanada's 2011 Annual Report. These risks remain substantially unchanged since December 31, 2011.

Controls and Procedures

As of March 31, 2012, an evaluation was carried out under the supervision of, and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of TransCanada's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of TransCanada's disclosure controls and procedures were effective at a reasonable assurance level as at March 31, 2012.

During the quarter ended March 31, 2012, there have been no changes in TransCanada's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, TransCanada's internal control over financial reporting.

Outlook

Since the disclosure in TransCanada's 2011 Annual Report, the Company's overall earnings outlook for 2012 will be moderately impacted by the delay in the return to service of Bruce Power's Unit 2 to second quarter 2012. In addition, reduced demand for natural gas and electricity due to unseasonably warm weather, combined with continued strong U.S. natural gas production, has resulted in historically high natural gas storage levels and low natural gas prices, which could have a negative impact on revenues in U.S. Pipelines, and power prices in Canadian and U.S. Power. The Company's earnings outlook could also be affected by the uncertainty and ultimate resolution of the capacity pricing issues in New York and resolution of the Sundance A PPA dispute, as discussed in the Recent Developments section of this MD&A. For further information on outlook, refer to the MD&A in TransCanada's 2011 Annual Report.

Recent Developments

Natural Gas Pipelines

Canadian Mainline
2012-2013 Tolls Application
Further to the comprehensive tolls application filed with the NEB in 2011 to change the business structure and the terms and conditions of service for the Canadian Mainline, TransCanada is working with the NEB and other stakeholders by exchanging information in advance of the oral hearing scheduled to commence in Calgary in June 2012. The hearing is scheduled to conclude in September 2012 with a decision expected in late 2012 or early 2013.

Marcellus Facilities Expansion
Further to the Application that was re-filed in November 2011 to construct new pipeline infrastructure to provide Southern Ontario with additional natural gas supply from the Marcellus shale basin, TransCanada filed responses to NEB information requests in January 2012. In a February 2012 letter, the NEB indicated it would not convene a hearing for the Application but would continue to assess the Application as a non-hearing application. Assuming the project receives approval to proceed, construction is scheduled to begin in early July 2012, with planned completion in November 2012. The capital cost of the Marcellus Facilities Expansion is expected to be approximately $130 million.

Mainline New Capacity Open Season
A New Capacity Open Season (NCOS) on the Canadian Mainline, that remains open until May 2012, was announced to capture additional Marcellus supply at the Niagara or Chippawa border points, as well as from other receipt points on the integrated system to all delivery points downstream of Parkway such as Iroquois/Waddington, GMI EDA and East Hereford. The NCOS is in response to shippers that have expressed interests for new firm transportation capacity. New service start dates of November 2013 and November 2014 are proposed, subject to all necessary regulatory approvals.

Alberta System

Expansion Projects

During the first four months of 2012, TransCanada has substantially completed 10 separate pipeline projects for the Alberta System at a cost of approximately $600 million.

ATCO Pipelines Commercial Integration

Commercial integration of the Alberta System and ATCO Pipelines (ATCO) commenced in October 2011. TransCanada continues to work with ATCO to gather information for the final stage of the integration which is to swap assets of equal value. As a result, the expected timing of the asset swap application, which was to be completed in first quarter 2012, has been delayed until mid-2012.

Tamazunchale Pipeline Extension Bid

TransCanada was awarded the approximately $500 million Tamazunchale Pipeline Extension Project in Mexico and executed a contract with the Comisión Federal de Electricidad in February 2012. Engineering, Procurement and Construction contracts have been executed and construction related activities have begun. The pipeline is expected to be in service in first quarter 2014.

Alaska Pipeline Project

The Alaska North Slope producers (ExxonMobil, ConocoPhillips and BP), along with TransCanada through its participation in the Alaska Pipeline Project, announced in March 2012 that the companies have agreed on a work plan aimed at commercializing North Slope natural gas resources via a liquefied natural gas (LNG) option. TransCanada has applied to the State of Alaska for a project plan amendment under the Alaska Gasline Inducement Act (AGIA) license to curtail work on the Alberta pipeline option in a way that preserves project assets and defers the Federal Energy Regulatory Commission (FERC) filing date until October 2014 (rather than October 2012 under the current AGIA provisions), while the preliminary assessment of the LNG alternative is underway.

Mackenzie Gas Project

The proponents of the Mackenzie Gas Project have been unable to finalize commercial terms which would allow the project to advance under current market conditions. As a result, project activities have been curtailed. TransCanada's future funding obligations for the Aboriginal Pipeline Group during such curtailment are expected to be nominal.

Oil Pipelines

Gulf Coast Project

The Company announced in February 2012 that what had previously been the Cushing to U.S. Gulf Coast portion of the Keystone XL Project has its own independent value to the marketplace and will be constructed as the stand-alone Gulf Coast Project, not part of the Presidential Permit process. The approximate cost of the 36-inch line is US$2.3 billion and, subject to regulatory approvals, TransCanada expects the Gulf Coast Project to be in service in mid to late 2013. As of March 31, 2012, US$0.8 billion has been invested in the program. Included in the US$2.3 billion cost is US$300 million for the 76 kilometre (47-mile) Houston Lateral pipeline that will transport oil to Houston refineries.

Keystone XL Pipeline

Also in February, TransCanada sent a letter to the U.S. Department of State (DOS) informing the Department the Company plans to re-file a Presidential Permit application (cross border permit) in the near future for the Keystone XL Project from the U.S./Canada border in Montana to Steele City, Nebraska. TransCanada noted it would supplement that application with an alternative route in Nebraska as soon as that route is selected. The application will include the already reviewed route in Montana and South Dakota. The over three year environmental review for Keystone XL completed last summer was the most comprehensive process ever for a cross border pipeline. Based on that work, TransCanada expects its cross border permit should be processed expeditiously and a decision made once a new route in Nebraska is determined.

Earlier this month, legislation was passed in Nebraska and signed into law by the Governor that enabled TransCanada to re-engage with the State's Department of Environmental Quality (DEQ), allowing the Company to continue to work collaboratively in determining an alternative route for Keystone XL that avoids the Sandhills. Alternative routing corridors and a preferred corridor were submitted to the DEQ April 18, 2012. The Department will now oversee the public comment and review process as TransCanada develops a specific alternate route.

The capital cost of Keystone XL is estimated to be US$5.3 billion, with US$1.5 billion having been invested as of March 31, 2012. The remainder will be spent between now and the in-service date of the expansion, which is expected by late 2014 or early 2015.

Keystone Hardisty Terminal

In March 2012, TransCanada launched and concluded an open season to obtain binding commitments for the Keystone Hardisty Terminal. The two million barrel project located at Hardisty, Alberta will provide new infrastructure for Western Canadian producers and access to the Keystone Pipeline System. TransCanada is currently reviewing the results of the open season. The Keystone Hardisty Terminal is expected to be operational by late 2014 or early 2015.

Energy

Bruce Power

In March 2012, Bruce Power received authorization from the Canadian Nuclear Safety Commission to restart Unit 2, effectively ending the construction and commissioning phases of the project. The reactor is presently producing steam and final safety checks are being conducted. Commercial operations for Unit 2 are expected to commence in second quarter 2012. Commissioning work on Unit 1 is currently underway and Bruce Power expects commercial operations for Unit 1 to commence in mid-third quarter 2012. TransCanada's share of the total net capital cost is expected to be approximately $2.4 billion.

In accordance with the terms of the Bruce Power Refurbishment Implementation Agreement (BPRIA), Bruce A receives Contingent Support Payments (CSP) from the OPA equal to the difference between the fixed prices under the BPRIA and spot market prices through July 1, 2012 after which all of the output from Bruce A will be subject to spot market prices until both Units 1 and 2 have achieved commercial operations.

Sundance A

The arbitration hearing to address the Sundance A force majeure and economic destruction claims dispute commenced April 9, 2012. The hearing is expected to conclude in May 2012 and TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $30 million of EBITDA for the three months ended March 31, 2012 and $188 million since the interruption began. The outcome of any arbitration process is not certain. However, TransCanada believes the matter will be resolved in its favour. The Company expects that its unamortized carrying value as at March 31, 2012 of $74 million related to the Sundance A PPA in Intangibles and Other Assets remains fully recoverable under the terms of the PPA, regardless of the outcome of the arbitration process.

Ravenswood
Spot market capacity prices in the New York Zone J market have increased in first quarter 2012 compared to the prior year primarily due to the combination of higher demand curve rates which were reset in late third quarter 2011 and rule changes implemented by the New York Independent System Operator's (NYISO) which changed the way certain capacity is measured in this market.

In 2011, TransCanada and other parties filed formal complaints with FERC regarding application of pricing rules by the NYISO. These complaints are still pending. The outcome of the complaints and longer-term impact that this development may have on Ravenswood is unknown.

Share Information

At April 24, 2012, TransCanada had 704 million issued and outstanding common shares, and had 22 million Series 1, 14 million Series 3 and 14 million Series 5 issued and outstanding first preferred shares that are convertible to 22 million Series 2, 14 million Series 4 and 14 million Series 6 preferred shares, respectively. In addition, there were nine million outstanding options to purchase common shares, of which five million were exercisable as at April 24, 2012.

Selected Quarterly Consolidated Financial Data[1]

(unaudited)	2012	2011				2010		
(millions of dollars, except per share amounts)	**First**	Fourth	Third	Second	First	Fourth	Third	Second
Revenues	**1,911**	1,967	1,987	1,797	1,868	1,675	1,776	1,616
Net income attributable to controlling interests	**366**	390	399	367	425	277	393	290
Share Statistics								
Net Income per common share								
Basic	**$0.50**	$0.53	$0.55	$0.50	$0.59	$0.38	$0.55	$0.41
Diluted	**$0.50**	$0.53	$0.55	$0.50	$0.59	$0.37	$0.55	$0.41
Dividend declared per common share	**$0.44**	$0.42	$0.42	$0.42	$0.42	$0.40	$0.40	$0.40

(1) The selected quarterly consolidated financial data has been prepared in accordance with U.S. GAAP and is presented in Canadian dollars.

Factors Affecting Quarterly Financial Information
In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated natural gas pipelines and regulated natural gas storage facilities, annual revenues, EBIT and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Oil Pipelines, which consists of the Company's investment in the Keystone Pipeline System, earnings are primarily generated by contractual arrangements for committed capacity that are not dependent on actual throughput. Quarter-over-quarter revenues, EBIT and net income during any particular fiscal year remain relatively stable with fluctuations resulting from planned and unplanned outages, and changes in the amount of spot volumes transported and the associated rate charged. Spot volumes transported are affected by customer demand, market pricing, planned and unplanned outages of refineries, terminals and pipeline facilities, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues, EBIT and net income are affected by seasonal weather conditions, customer demand, market prices, capacity prices, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

Significant developments that affected the last eight quarters' EBIT and Net Income are as follows:

- First Quarter 2012, EBIT included net realized losses of $22 million pre-tax ($11 million after tax) from certain risk management activities.

- Fourth Quarter 2011, EBIT excluded net unrealized gains of $9 million pre-tax ($11 million after tax) resulting from certain risk management activities.

- Third Quarter 2011, Energy's EBIT included the positive impact of higher prices for Western Power. EBIT included net unrealized losses of $43 million pre-tax ($30 million after tax) resulting from certain risk management activities.

- Second Quarter 2011, Natural Gas Pipelines' EBIT included incremental earnings from Guadalajara, which was placed in service in June 2011. Energy's EBIT included incremental earnings from Coolidge, which was placed in service in May 2011. EBIT included net unrealized losses of $3 million pre-tax ($2 million after tax) resulting from certain risk management activities.

- First Quarter 2011, Natural Gas Pipelines' EBIT included incremental earnings from Bison, which was placed in service in January 2011. Oil Pipelines began recording EBIT for the Wood River/Patoka and Cushing Extension sections of the Keystone Pipeline System in February 2011. EBIT included net unrealized losses of $19 million pre-tax ($12 million after tax) resulting from certain risk management activities.

- Fourth Quarter 2010, Natural Gas Pipelines' EBIT decreased as a result of recording a $146 million pre-tax ($127 million after tax) valuation provision for advances to the Aboriginal Pipeline Group for the Mackenzie Gas Project. Energy's EBIT included contributions from the second phase of Kibby Wind, which was placed in service in October 2010, and net unrealized gains of $46 million pre-tax ($29 million after tax) resulting from certain risk management activities.

- Third Quarter 2010, Natural Gas Pipelines' EBIT increased as a result of recording nine months of incremental earnings related to the Alberta System 2010 – 2012 Revenue Requirement Settlement, which resulted in a $33 million increase to Net Income. Energy's EBIT included contributions from Halton Hills, which was placed in service in September 2010, and net unrealized loss of $1million pre-tax ($1 million after tax) resulting from certain risk management activities.

- Second Quarter 2010, Energy's EBIT included net unrealized gains of $16 million pre-tax ($11 million after tax) resulting from certain risk management activities. Net Income reflected a decrease of $58 million after tax due to losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of U.S. dollar-denominated working capital balances.

Condensed Consolidated Statement of Income

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars except per share amounts)*	2012	2011 Adjusted (Note 1)
Revenues		
Natural Gas Pipelines	**1,085**	1,062
Oil Pipelines	**259**	135
Energy	**567**	671
	1,911	1,868
Income from Equity Investments	**60**	121
Operating and Other Expenses		
Plant operating costs and other	**707**	609
Commodity purchases resold	**179**	238
Depreciation and amortization	**344**	320
	1,230	1,167
Financial Charges/(Income)		
Interest expense	**242**	211
Interest income and other	**(31)**	(30)
	211	181
Income before Income Taxes	**530**	641
Income Taxes Expense		
Current	**56**	106
Deferred	**73**	74
	129	180
Net Income	**401**	461
Net Income Attributable to Non-Controlling Interests	**35**	36
Net Income Attributable to Controlling Interests	**366**	425
Preferred Share Dividends	**14**	14
Net Income Attributable to Common Shares	**352**	411
Net Income per Common Share		
Basic and Diluted	**$0.50**	$0.59
Dividends Declared per Common Share	**$0.44**	$0.42
Weighted-average Number of Common Shares (millions)		
Basic	**704**	698
Diluted	**705**	699

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Comprehensive Income

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	2012	2011 Adjusted (Note 1)
Net Income	**401**	461
Other Comprehensive (Loss)/Income, Net of Income Taxes		
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(107)**	(116)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	**38**	49
Change in fair value of derivative instruments designated as cash flow hedges[3]	**(45)**	(53)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4]	**45**	48
Reclassification to Net Income of actuarial (gains)/losses and prior service costs on pension and other post-retirement benefit plans[5]	**10**	2
Other Comprehensive Loss of Equity Investments[6]	**5**	2
Other Comprehensive Loss	**(54)**	(68)
Comprehensive Income	**347**	393
Comprehensive Income Attributable to Non-Controlling Interests	**18**	21
Comprehensive Income Attributable to Controlling Interests	**329**	372
Preferred Share Dividends	**14**	14
Comprehensive Income Attributable to Common Shares	**315**	358

(1) Net of income tax expense of $22 million for the three months ended March 31, 2012 (2011 – expense of $29 million).
(2) Net of income tax expense of $11 million for the three months ended March 31, 2012 (2011 – expense of $19 million).
(3) Net of income tax recovery of $34 million for the three months ended March 31, 2012 (2011 – recovery of $19 million).
(4) Net of income tax expense of $21 million for the three months ended March 31, 2012 (2011 – expense of $25 million).
(5) Net of income tax recovery of $4 million for the three months ended March 31, 2012 (2011 – expense of $1 million).
(6) Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, gains and losses on derivative instruments designated as cash flow hedges, offset by change in gains and losses on derivative instruments designated as cash flow hedges, net of income tax expense of $1 million for the three months ended March 31, 2012 (2011 – expense of $1 million).

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Cash Flows

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	2012	2011 Adjusted (Note 1)
Cash Generated from Operations		
Net income	**401**	461
Depreciation and amortization	**344**	320
Deferred income taxes	**73**	74
Income from equity investments	**(60)**	(121)
Distributions received from equity investments	**53**	65
Employee future benefits expense in excess of/(less than) funding	**7**	(3)
Other	**23**	19
(Increase)/decrease in operating working capital	**(169)**	19
Net cash provided by operations	**672**	834
Investing Activities		
Capital expenditures	**(464)**	(567)
Equity investments	**(216)**	(151)
Deferred amounts and other	**(7)**	65
Net cash used in investing activities	**(687)**	(653)
Financing Activities		
Dividends on common and preferred shares	**(310)**	(200)
Distributions paid to non-controlling interests	**(33)**	(27)
Notes payable (repaid)/issued, net	**(46)**	134
Long-term debt issued, net of issue costs	**492**	-
Reduction of long-term debt	**(548)**	(321)
Common shares issued	**14**	21
Net cash used in financing activities	**(431)**	(393)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(12)**	(12)
Decrease in Cash and Cash Equivalents	**(458)**	(224)
Cash and Cash Equivalents		
Beginning of period	**654**	660
Cash and Cash Equivalents		
End of period	**196**	436

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Balance Sheet

(unaudited) *(millions of Canadian dollars)*	**March 31 2012**	December 31 2011 Adjusted (Note 1)
ASSETS		
Current Assets		
Cash and cash equivalents	**196**	654
Accounts receivable	**1,067**	1,094
Inventories	**239**	248
Other	**1,235**	1,114
	2,737	3,110
Plant, Property and Equipment, net of accumulated depreciation of $15,657 and $15,406, respectively	**32,175**	32,467
Equity Investments	**5,298**	5,077
Goodwill	**3,472**	3,534
Regulatory Assets	**1,655**	1,684
Intangibles and Other Assets	**1,558**	1,466
	46,895	47,338
LIABILITIES		
Current Liabilities		
Notes payable	**1,787**	1,863
Accounts payable	**2,146**	2,359
Accrued interest	**360**	365
Current portion of long-term debt	**424**	935
	4,717	5,522
Regulatory Liabilities	**309**	297
Deferred Amounts	**974**	929
Deferred Income Tax Liabilities	**3,664**	3,591
Long-Term Debt	**17,973**	17,724
Junior Subordinated Notes	**998**	1,016
	28,635	29,079
EQUITY		
Common shares, no par value	**12,026**	12,011
Issued and outstanding: March 31, 2012 - 704 million shares		
December 31, 2011 - 704 million shares		
Preferred shares	**1,224**	1,224
Additional paid-in capital	**379**	380
Retained earnings	**4,670**	4,628
Accumulated other comprehensive loss	**(1,486)**	(1,449)
Controlling Interests	**16,813**	16,794
Non-controlling interests	**1,447**	1,465
Equity	**18,260**	18,259
	46,895	47,338

Contingencies and Guarantees (Note 8)

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Accumulated Other Comprehensive (Loss)/Income

(unaudited) *(millions of Canadian dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Pension and Other Post-retirement Plan Adjustments	Total
Balance at December 31, 2011	(643)	(281)	(525)	(1,449)
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**(90)**	**-**	**-**	**(90)**
Change in fair value of derivative instruments to hedge net investments in foreign operations(2)	**38**	**-**	**-**	**38**
Change in fair value of derivative instruments designated as cash flow hedges(3)	**-**	**(45)**	**-**	**(45)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)(5)	**-**	**45**	**-**	**45**
Reclassification of actuarial losses and prior service costs on pension and other post-retirement benefit plans(6)	**-**	**-**	**10**	**10**
Other Comprehensive Income of equity investments (7)	**-**	**1**	**4**	**5**
Balance at March 31, 2012	**(695)**	**(280)**	**(511)**	**(1,486)**

(unaudited) *(adjusted Note 1)* *(millions of Canadian dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Pension and Other Post-retirement Plan Adjustments	Total
Balance at December 31, 2010	(683)	(194)	(366)	(1,243)
Change in foreign currency translation gains and losses on investments in foreign operations(1)	(98)	-	-	(98)
Change in fair value of derivative instruments to hedge net investments in foreign operations(2)	49	-	-	49
Change in fair value of derivative instruments designated as cash flow hedges(3)	-	(54)	-	(54)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges(4)(5)	-	46	-	46
Reclassification of actuarial losses and prior service costs on pension and other post-retirement benefit plans(6)	-	-	2	2
Other Comprehensive (Loss)/Income of equity investments (7)	-	(2)	4	2
Balance at March 31, 2011	(732)	(204)	(360)	(1,296)

(1) Net of income tax expense of $22 million and non-controlling interest losses of $17 million for the three months ended March 31, 2012 (2011 – expense of $29 million; loss of $18 million).

(2) Net of income tax expense of $11 million for the three months ended March 31, 2012 (2011 – expense of $19 million).

(3) Net of income tax recovery of $34 million and non-controlling interest losses of nil for the three months ended March 31, 2012 (2011 – recovery of $19 million; gain of $1 million).

(4) Net of income tax expense of $21 million and non-controlling interest losses of nil for the three months ended March 31, 2012 (2011 – expense of $25 million; gain of $2 million).

(5) Losses related to cash flow hedges reported in AOCI and expected to be reclassified to Net Income in the next 12 months are estimated to be $197 million ($120 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

(6) Net of income tax recovery of $4 million for the three months ended March 31, 2012 (2011 – expense of $1 million).

(7) Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges, partially offset by changes in gains and losses on derivative instruments designated as cash flow hedges, net of income tax expense of $1 million for the three months ended March 31, 2012 (2011 – expense of $1 million).

See accompanying notes to the condensed consolidated financial statements.

Condensed Consolidated Statement of Equity

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	2012	2011 Adjusted (Note 1)
Common Shares		
Balance at beginning of period	**12,011**	11,745
Shares issued under dividend reinvestment plan	**-**	93
Proceeds from shares issued on exercise of stock options	**15**	21
Balance at end of period	**12,026**	11,859
Preferred Shares		
Balance at beginning and end of period	**1,224**	1,224
Additional Paid-In Capital		
Balance at beginning of period	**380**	349
Exercise of stock options, net of issuance	**(1)**	-
Balance at end of period	**379**	349
Retained Earnings		
Balance at beginning of period	**4,628**	4,273
Net income attributable to controlling interests	**366**	425
Common share dividends	**(310)**	(294)
Preferred share dividends	**(14)**	(14)
Balance at end of period	**4,670**	4,390
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,449)**	(1,243)
Other comprehensive loss	**(37)**	(53)
Balance at end of period	**(1,486)**	(1,296)
Equity Attributable to Controlling Interests	**16,813**	16,526
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,465**	1,157
Net income attributable to non-controlling interest	**35**	36
Other comprehensive loss attributable to non-controlling interest	**(17)**	(15)
Distributions to non-controlling interests	**(33)**	(27)
Other	**(3)**	(2)
Balance at end of period	**1,447**	1,149
Total Equity	**18,260**	17,675

See accompanying notes to the condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements (Unaudited)

1. Basis of Presentation

These condensed consolidated financial statements of TransCanada Corporation (TransCanada or the Company) have been prepared by management in accordance with United States generally accepted accounting principles (U.S. GAAP). Comparative figures, which were previously presented in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook (CGAAP), have been adjusted as necessary to be compliant with the Company's policies under U.S. GAAP. The amounts adjusted for U.S. GAAP presented in these condensed consolidated financial statements for the three months ended March 31, 2011 are the same as those that have been previously reported in the Company's March 31, 2011 Reconciliation to U.S. GAAP. The amounts adjusted at December 31, 2011 are the same as those reported in Note 25 of TransCanada's 2011 audited Consolidated Financial Statements included in TransCanada's 2011 Annual Report. The accounting policies applied are consistent with those outlined in TransCanada's 2011 Annual Report, except as described in Note 2, which outlines the Company's significant accounting policies that have changed upon adoption of U.S. GAAP. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TransCanada's 2011 Annual Report.

These condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect the financial position and results of operations for the respective periods. These condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2011 audited Consolidated Financial Statements included in TransCanada's 2011 Annual Report. Certain comparative figures have been reclassified to conform with the current period's presentation.

Earnings for interim periods may not be indicative of results for the fiscal year in the Company's Natural Gas Pipeline segment due to seasonal fluctuations in short-term throughput volumes on U.S. pipelines. Earnings for interim periods may also not be indicative of results for the fiscal year in the Company's Energy segment due to the impact of seasonal weather conditions on customer demand and market pricing in certain of the Company's investments in electrical power generation plants and non-regulated gas storage facilities.

Use of Estimates and Judgements

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies summarized below.

2. Changes in Accounting Policies

Changes to Significant Accounting Policies Upon Adoption of U.S. GAAP

Principles of Consolidation
The condensed consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TransCanada uses the equity method of accounting for corporate joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TransCanada records its proportionate share of undivided interests in certain assets.

Inventories
Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are recorded at the lower of weighted average cost or market.

Income Taxes
The Company uses the liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Employee Benefit and Other Plans
The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans' as an asset or liability on its Balance Sheet and recognizes changes in that funded status through Other Comprehensive (Loss)/Income (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated Other Comprehensive (Loss)/Income (AOCI) over the average remaining service period of the active employees. For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains and losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the average remaining service life of active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Long-Term Debt Transaction Costs
Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company records long-term debt transaction costs as deferred assets and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

Guarantees
Upon issuance, the Company records the fair value of certain guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to Equity Investments, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Changes in Accounting Policies for 2012

Fair Value Measurement
Effective January 1, 2012, the Company adopted the Accounting Standards Update (ASU) on fair value measurements as issued by the Financial Accounting Standards Board (FASB). Adoption of the ASU has resulted in an increase in the qualitative and quantitative disclosures regarding Level III measurements.

Intangibles – Goodwill and Other
Effective January 1, 2012, the Company adopted the ASU on testing goodwill for impairment as issued by the FASB. Adoption of the ASU has resulted in a change in the accounting policy related to testing goodwill for impairment, as the Company is now permitted under U.S. GAAP to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount as a basis for determining whether it is required to proceed to the two-step quantitative impairment test.

Future Accounting Changes

Balance Sheet Offsetting/Netting
In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting arrangement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an

increase in disclosure regarding financial instruments which are subject to offsetting as described in this amendment.

3. Segmented Information

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	Natural Gas Pipelines		Oil Pipelines[(1)]		Energy		Corporate		Total	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Revenues	**1,085**	1,062	**259**	135	**567**	671	**-**	-	**1,911**	1,868
Income from equity investments	**46**	43	**-**	-	**14**	78	**-**	-	**60**	121
Plant operating costs and other	**(406)**	(332)	**(86)**	(36)	**(186)**	(217)	**(29)**	(24)	**(707)**	(609)
Commodity purchases resold	**-**	-	**-**	-	**(179)**	(238)	**-**	-	**(179)**	(238)
Depreciation and amortization	**(232)**	(228)	**(36)**	(23)	**(73)**	(66)	**(3)**	(3)	**(344)**	(320)
	493	545	**137**	76	**143**	228	**(32)**	(27)	**741**	822
Interest expense									**(242)**	(211)
Interest income and other									**31**	30
Income before Income Taxes									**530**	641
Income taxes expense									**(129)**	(180)
Net Income									**401**	461
Net Income Attributable to Non-Controlling Interests									**(35)**	(36)
Net Income Attributable to Controlling Interests									**366**	425
Preferred Share Dividends									**(14)**	(14)
Net Income Attributable to Common Shares									**352**	411

(1) Commencing in February 2011, TransCanada began recording earnings related to the Wood River/Patoka and Cushing Extension sections of Keystone.

Total Assets

(unaudited) *(millions of Canadian dollars)*	**March 31, 2012**	December 31, 2011
Natural Gas Pipelines	**22,813**	23,161
Oil Pipelines	**9,378**	9,440
Energy	**13,675**	13,269
Corporate	**1,029**	1,468
	46,895	47,338

4. Income Taxes

At March 31, 2012, the total unrecognized tax benefit of uncertain tax positions is approximately $56 million (December 31, 2011 - $52 million). TransCanada recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in net tax expense for the three months ended March 31, 2012 is $1 million of interest expense and nil for penalties (March 31, 2011 - $1 million for interest expense and nil for penalties). At March 31, 2012, the Company had $8 million accrued for interest expense and nil accrued for penalties (December 31, 2011 - $7 million accrued for interest expense and nil accrued for penalties).

The effective tax rates for the three-month periods ended March 31, 2012 and 2011 were 24 per cent and 28 per cent, respectively. The lower effective tax rate in 2012 was a result of a reduction in the Canadian statutory tax rate, changes in the proportion of income earned between Canadian and foreign jurisdictions and higher positive tax adjustments in 2012.

TransCanada expects the enactment of certain Canadian Federal tax legislation in the next twelve months which is expected to result in a favourable income tax adjustment of approximately $22 million. Otherwise, subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

5. Long-Term Debt

In the three months ended March 31, 2012, the Company capitalized interest related to capital projects of $74 million (March 31, 2011 - $97 million).

In January 2012, TransCanada PipeLine USA Ltd. repaid the remaining principal of US$500 million on its five-year term loan.

In March 2012, TransCanada PipeLines Limited issued US$500 million of 0.875 per cent Senior Notes due in 2015.

6. Employee Post-Retirement Benefits

The net benefit plan expense for the Company's defined benefit pension plans and other post-retirement benefit plans is as follows:

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars)*	Pension Benefit Plans **2012**	 2011	Other Post-retirement Benefit Plans **2012**	 2011
Service cost	**16**	14	**1**	-
Interest cost	**23**	23	**2**	2
Expected return on plan assets	**(28)**	(28)	**-**	-
Amortization of actuarial loss	**5**	3	**-**	-
Amortization of regulatory asset	**5**	4	**-**	-
Net Benefit Cost Recognized	**21**	16	**3**	2

7. Financial Instruments and Risk Management

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At March 31, 2012, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10.4 billion (US$10.4 billion) and a fair value of $12.9 billion (US$12.9 billion). At March 31, 2012, $97 million (December 31, 2011 - $79 million) was included in Other Current Assets, $83 million (December 31, 2011 - $66 million) was included in Intangibles and Other Assets, $4 million (December 31, 2011 - $15 million) was included in Accounts Payable and $30 million (December 31, 2011 - $41 million) was included in Deferred Amounts for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

The fair values and notional principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability) *(unaudited)* *(millions of Canadian dollars)*	**March 31, 2012** **Fair Value**(1)	**March 31, 2012** **Notional or Principal Amount**	December 31, 2011 Fair Value(1)	December 31, 2011 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2019)(2)	**128**	**US 4,150**	93	US 3,850
U.S. dollar forward foreign exchange contracts (maturing 2012)	**18**	**US 1,165**	(4)	US 725
	146	**US 5,315**	89	US 4,575

(1) Fair values equal carrying values.
(2) Consolidated Net Income in first quarter 2012 included net realized gains of $7 million (2011 – gains of $5 million) related to the interest component of cross-currency swap settlements.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

(unaudited) *(millions of Canadian dollars)*	**March 31, 2012** **Carrying Amount**(1)	**March 31, 2012** **Fair Value**(2)	December 31, 2011 Carrying Amount(1)	December 31, 2011 Fair Value(2)
Financial Assets				
Cash and cash equivalents	**196**	**196**	654	654
Accounts receivable and other(3)	**1,326**	**1,369**	1,359	1,403
Available-for-sale assets(3)	**34**	**34**	23	23
	1,556	**1,599**	2,036	2,080
Financial Liabilities(4)				
Notes payable	**1,787**	**1,787**	1,863	1,863
Accounts payable and deferred amounts(5)	**1,016**	**1,016**	1,329	1,329
Accrued interest	**360**	**360**	365	365
Long-term debt	**18,397**	**23,313**	18,659	23,757
Junior subordinated notes	**998**	**1,031**	1,016	1,027
	22,558	**27,507**	23,232	28,341

(1) Recorded at amortized cost, except for US$350 million (December 31, 2011 – US$350 million) of Long-Term Debt that is recorded at fair value. This debt which is recorded at fair value on a recurring basis is classified in Level II of the fair value category using the income approach based on interest rates from external data service providers.
(2) The fair value measurement of financial assets and liabilities recorded at amortized cost for which the fair value is not equal to the carrying value would be included in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.
(3) At March 31, 2012, the Condensed Consolidated Balance Sheet included financial assets of $1,068 million (December 31, 2011 – $1,094 million) in Accounts Receivable, $33 million (December 31, 2011 – $41 million) in Other Current Assets and $259 million (December 31, 2011 - $247 million) in Intangibles and Other Assets.
(4) Consolidated Net Income in first quarter 2012 included losses of $15 million (2011 – losses of $9 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2011 – US$350 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.
(5) At March 31, 2012, the Condensed Consolidated Balance Sheet included financial liabilities of $886 million (December 31, 2011 – $1,192 million) in Accounts Payable and $130 million (December 31, 2011 - $137 million) in Deferred Amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

March 31, 2012 *(unaudited)* *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$314**	**$189**	**$9**	**$19**
Liabilities	**$(329)**	**$(232)**	**$(13)**	**$(19)**
Notional Values				
Volumes[3]				
Purchases	**31,088**	**104**	**-**	**-**
Sales	**29,851**	**76**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**684**
U.S. dollars	**-**	**-**	**US 1,476**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized (losses)/gains in the three months ended March 31, 2012[4]	**$(7)**	**$(14)**	**$6**	**$-**
Net realized gains/(losses) in the three months ended March 31, 2012[4]	**$15**	**$(10)**	**$9**	**$-**
Maturity dates	**2012-2016**	**2012-2016**	**2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$40**	**$-**	**$-**	**$15**
Liabilities	**$(321)**	**$(23)**	**$(39)**	**$-**
Notional Values				
Volumes[3]				
Purchases	**21,455**	**6**	**-**	**-**
Sales	**8,704**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 42**	**US 350**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized (losses)/gains in the three months ended March 31, 2012[4]	**$(32)**	**$(6)**	**$-**	**$1**
Maturity dates	**2012-2017**	**2012-2013**	**2012-2014**	**2013-2015**

(1) All derivative financial instruments held for trading have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(4) Realized and unrealized gains and losses on derivative financial instruments held for trading used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in cash flow hedging relationships is initially recognized in Other Comprehensive Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $15 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three months ended March 31, 2012 were $2 million and were included in Interest Expense. In first quarter 2012, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three months ended March 31, 2012, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

2011

(unaudited) *(millions of Canadian dollars unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2][3]				
Assets	$185	$176	$3	$22
Liabilities	$(192)	$(212)	$(14)	$(22)
Notional Values[3]				
Volumes[4]				
Purchases	21,905	103	-	-
Sales	21,334	82	-	-
Canadian dollars	-	-	-	684
U.S. dollars	-	-	US 1,269	US 250
Cross-currency	-	-	47/US 37	-
Net unrealized (losses)/gains in the three months ended March 31, 2011[5]	$(1)	$(16)	$2	$(1)
Net realized (losses)/gains in the three months ended March 31, 2011[5]	$(1)	$(26)	$21	$1
Maturity dates	2012-2016	2012-2016	2012	2012-2016
Derivative Financial Instruments in Hedging Relationships[6][7]				
Fair Values[2][3]				
Assets	$16	$3	$-	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional Values[3]				
Volumes[4]				
Purchases	17,188	8	-	-
Sales	8,061	-	-	-
U.S. dollars	-	-	US 73	US 600
Cross-currency	-	-	136/US 100	-
Net realized losses in the three months ended March 31, 2011[5]	$(43)	$(3)	$-	$(1)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

(1) All derivative financial instruments held for trading have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) As at December 31, 2011.

(4) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(5) Realized and unrealized gains and losses on derivative financial instruments held for trading used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in cash flow hedging relationships is initially recognized in Other Comprehensive Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(6) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million at December 31, 2011. Net realized gains on fair value hedges for the three months ended March 31, 2011 were $2 million and were included in Interest Expense. In first quarter 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(7) For the three months ended March 31, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts were excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

(unaudited) *(millions of Canadian dollars)*	**March 31 2012**	December 31 2011
Current		
Other current assets	**503**	361
Accounts payable	**(607)**	(485)
Long term		
Intangibles and other assets	**263**	202
Deferred amounts	**(403)**	(349)

Derivatives in Cash Flow Hedging Relationships

The components of OCI related to derivatives in cash flow hedging relationships are as follows:

Three months ended March 31 *(unaudited)* *(millions of Canadian dollars, pre-tax)*	Cash Flow Hedges Power 2012	Power 2011	Natural Gas 2012	Natural Gas 2011	Foreign Exchange 2012	Foreign Exchange 2011	Interest 2012	Interest 2011
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**(66)**	(55)	**(10)**	(11)	**(3)**	(6)	**-**	-
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**47**	34	**13**	28	**-**	-	**6**	9
Losses on derivative instruments recognized in earnings (ineffective portion)	**(6)**	(2)	**(2)**	(1)	**-**	-	**-**	-

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at March 31, 2012, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $110 million (2011 - $86 million), for which the Company had provided collateral of $53 million (2011 - $3 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on March 31, 2012, the Company would have been required to provide additional collateral of $57 million (2011 - $83 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's assets and liabilities recorded at fair value have been classified into three categories based on the fair value hierarchy.

In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.

In Level II, the fair value of interest rate and foreign exchange derivative assets and liabilities is determined using the income approach. The fair value of power and gas commodity assets and liabilities is determined using the market approach. Under both approaches, valuation is based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Such inputs include published exchange rates, interest rates, interest rate swap curves, yield curves, and broker quotes from external data service providers. Transfers between Level I and Level II would occur when there is a change in market circumstances. There were no transfers between Level I and Level II in first quarter 2012 and 2011.

In Level III, the fair value of assets and liabilities measured on a recurring basis is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II. There were no transfers between Level II and Level III in first quarter 2012 and 2011.

Long-dated commodity transactions in certain markets where liquidity is low are included in Level III of the fair value hierarchy, as the related commodity prices are not readily observable. Long-term electricity prices are estimated using a third-party modelling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Inputs into the model include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices are based on a view of future natural gas supply and demand, as well as exploration and development costs. Long-term prices are reviewed by management and the Board on a periodic basis. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas would result in a lower fair value measurement of contracts included in Level III.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions, are categorized as follows:

(unaudited) (millions of Canadian dollars, pre-tax)	Quoted Prices in Active Markets (Level I) Mar 31 2012	 Dec 31 2011	Significant Other Observable Inputs (Level II) Mar 31 2012	 Dec 31 2011	Significant Unobservable Inputs (Level III) Mar 31 2012	 Dec 31 2011	Total Mar 31 2012	 Dec 31 2011
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**34**	36	**-**	-	**34**	36
Foreign exchange contracts	**-**	-	**187**	141	**-**	-	**187**	141
Power commodity contracts	**-**	-	**337**	201	**-**	-	**337**	201
Gas commodity contracts	**136**	124	**50**	55	**-**	-	**186**	179
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(19)**	(23)	**-**	-	**(19)**	(23)
Foreign exchange contracts	**-**	-	**(84)**	(102)	**-**	-	**(84)**	(102)
Power commodity contracts	**-**	-	**(621)**	(454)	**(11)**	(15)	**(632)**	(469)
Gas commodity contacts	**(228)**	(208)	**(25)**	(26)	**-**	-	**(253)**	(234)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**34**	23	**-**	-	**-**	-	**34**	23
	(58)	(61)	**(141)**	(172)	**(11)**	(15)	**(210)**	(248)

The following table presents the net change in the Level III fair value category:

Three months ended March 31 *(unaudited) (millions of Canadian dollars, pre-tax)*	Derivatives[(1)(2)] **2012**	 2011
Balance at January 1	**(15)**	(8)
New contracts	**-**	1
Total gains or losses included in OCI	**4**	(6)
Balance at March 31	**(11)**	(13)

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) At March 31, 2012, there were no unrealized gains or losses included in Net Income attributable to derivatives that were still held at the reporting date (2011 – nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at March 31, 2012.

8. Contingencies and Guarantees

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. With respect to 2012, TransCanada currently expects spot prices to be less than the floor price for the year, therefore no amounts recorded in revenues in first quarter 2012 are expected to be repaid.

Sundance A PPA

The arbitration hearing to address the Sundance A force majeure and economic destruction claims dispute commenced April 9, 2012. The hearing is expected to conclude in May 2012, and TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe the PPA owner's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $30 million of pre-tax income for the three months ended March 31, 2012 and $188 million since the interruption began. The outcome of any arbitration process is not certain. However, TransCanada believes the matter will be resolved in its favour. The Company expects that its unamortized carrying value as at March 31, 2012 of $74 million related to the Sundance A PPA in Intangibles and Other Assets remains fully recoverable under the terms of the PPA, regardless of the outcome of the arbitration process.

Guarantees

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees have terms ending in 2018 and 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $831 million at March 31, 2012. The fair value of these Bruce Power guarantees at March 31, 2012 is estimated to be $30 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these assurances was estimated at March 31, 2012 to range from $136 million to a maximum of $494 million. The fair value of these guarantees at March 31, 2012 is estimated to be $80 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

AGL RESOURCES INC (GAS)

10-Q

Quarterly report pursuant to sections 13 or 15(d)
Filed on 05/01/2012
Filed Period 03/31/2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 2012

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

Georgia	**58-2210952**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Ten Peachtree Place NE, Atlanta, Georgia 30309
(Address and zip code of principal executive offices)

404-584-4000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” ”accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☑

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	**Outstanding as of April 26, 2012**
Common Stock, $5.00 Par Value	117,310,372

AGL RESOURCES INC.

Quarterly Report on Form 10-Q

For the Quarter Ended March 31, 2012

TABLE OF CONTENTS

Glossary of Key Terms

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GLOSSARY OF KEY TERMS

2011 Form 10-K	Our Annual Report on Form 10-K for the year ended December 31, 2011, filed with the SEC on February 22, 2012
AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support the AGL Capital commercial paper program
Atlanta Gas Light	Atlanta Gas Light Company
Bcf	Billion cubic feet
Central Valley	Central Valley Gas Storage, LLC
Chattanooga Gas	Chattanooga Gas Company
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income and other income and excludes financing costs, including interest on debt and income tax expense each of which we evaluate on a consolidated level. As an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, earnings before income taxes, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP
ERC	Environmental remediation costs associated with our distribution operations segment which are generally recoverable through rate mechanisms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light
Georgia Natural Gas	The name under which SouthStar does business in Georgia
Golden Triangle Storage	Golden Triangle Storage, Inc.
Hampton Roads	Virginia Natural Gas' pipeline project which connects its northern and southern pipelines
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher because weather is colder
Henry Hub	A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced
Horizon Pipeline	Horizon Pipeline Company, LLC
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIBOR	London Inter-Bank Offered Rate
LOCOM	Lower of weighted average cost or current market price
Magnolia	Magnolia Enterprise Holdings, Inc.
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Merger Agreement	Agreement and Plan of Merger, dated December 6, 2010, as amended by and among the Company, Nicor, Apollo Acquisition Corp, an Illinois corporation and wholly owned subsidiary of the Company and Ottawa Acquisition LLC, an Illinois Limited Liability Company and a wholly owned subsidiary of the Company
Mcf	Thousand cubic feet
MGP	Manufactured gas plant
Moody's	Moody's Investors Service
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor	Nicor Inc. - an acquisition completed in December 2011 and former holding company of Nicor Gas

Nicor Advanced Energy	Prairie Point Energy, LLC, doing business as Nicor Advanced Energy
Nicor Gas	Northern Illinois Gas Company, doing business as Nicor Gas Company
Nicor Gas Credit Facility	$700 million credit facility entered into by Nicor Gas to support its commercial paper program
Nicor Services	Nicor Energy Services Company
Nicor Solutions	Nicor Solutions, LLC
NUI	NUI Corporation – an acquisition completed in November 2004
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as operating revenues minus cost of goods sold, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and gains or losses on the sale of our assets; these items are included in our calculation of operating income as reflected in our Consolidated Statements of Income. Operating margin should not be considered an alternative to, or more meaningful than, operating income as determined in accordance with GAAP
PBR	Performance-based rate, a regulatory plan that provided economic incentives based on natural gas cost performance
Piedmont	Piedmont Natural Gas Company, Inc.
PP&E	Property, plant and equipment
S&P	Standard & Poor's Ratings Services
Sawgrass Storage	Sawgrass Storage, LLC
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
Seven Seas	Seven Seas Insurance Company, Inc.
SNG	Substitute natural gas, a synthetic form of gas manufactured from coal
SouthStar	SouthStar Energy Services LLC
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Term Loan Facility	$300 million credit agreement entered into by AGL Capital to repay the $300 million senior notes due in 2011
TEU	Twenty-foot equivalent unit, a measure of volume in containerized shipping equal to one 20-foot-long container
Triton	Triton Container Investments LLC, a cargo container leasing company in which we have an investment
Tropical Shipping	A wholly owned business and a carrier of containerized freight in the Bahamas and the Caribbean region
VaR	Value at risk is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
WACOG	Weighted average cost of gas
WNA	Weather normalization adjustment

Glossary of Key Terms

PART 1 - Financial Information
Item 1. Financial Statements

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(UNAUDITED)

	As of		
In millions	**March 31, 2012**	**December 31, 2011**	**March 31, 2011**
Current assets			
Cash and cash equivalents	$ 71	$ 69	$ 85
Short-term investments	57	53	0
Receivables			
Energy marketing receivables	386	607	565
Gas, unbilled and other receivables	577	692	367
Less allowance for uncollectible accounts	19	15	21
Total receivables	944	1,284	911
Inventories, net	464	750	361
Derivative instruments – current portion	218	226	111
Regulatory assets – current portion	137	131	73
Other current assets	131	233	46
Total current assets	2,022	2,746	1,587
Long-term assets and other deferred debits			
Property, plant and equipment	9,920	9,779	6,348
Less accumulated depreciation	1,947	1,879	1,830
Property, plant and equipment, net	7,973	7,900	4,518
Goodwill	1,813	1,813	418
Regulatory assets – noncurrent portion	1,057	1,079	434
Derivative instruments – noncurrent portion	48	62	29
Other	326	313	40
Total long-term assets and other deferred debits	11,217	11,167	5,439
Total assets	$ 13,239	$ 13,913	$ 7,026
Current liabilities			
Energy marketing trade payables	$ 425	$ 590	$ 628
Accounts payable – trade	205	294	154
Regulatory liabilities – current portion	173	112	77
Accrued expenses	145	162	141
Accrued regulatory infrastructure program costs – current portion	149	131	69
Short-term debt	730	1,321	25
Derivative instruments – current portion	93	99	25
Accrued environmental remediation liabilities – current portion	39	37	15
Other current liabilities	389	338	179
Total current liabilities	2,348	3,084	1,313
Long-term liabilities and other deferred credits			
Long-term debt	3,558	3,561	2,173
Accumulated deferred income taxes	1,447	1,445	803
Regulatory liabilities – noncurrent portion	1,431	1,405	296
Accrued pension obligations	228	238	153
Accrued regulatory infrastructure program costs	110	145	143
Accrued environmental remediation liabilities	289	290	126
Accrued other retirement benefit costs	318	320	34
Derivative instruments – noncurrent portion	10	11	3
Other long-term liabilities and other deferred credits	74	75	62
Total long-term liabilities and other deferred credits	7,465	7,490	3,793
Total liabilities and other deferred credits	9,813	10,574	5,106
Commitments, guarantees and contingencies (see Note 9)			
Equity			
AGL Resources Inc. common shareholders' equity, $5 par value; 750,000,000 shares authorized	3,410	3,318	1,903
Noncontrolling interest	16	21	17
Total equity	3,426	3,339	1,920
Total liabilities and equity	$ 13,239	$ 13,913	$ 7,026

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

In millions, except per share amounts	Three months ended March 31, 2012	Three months ended March 31, 2011
Operating revenues	$ 1,404	$ 878
Operating expenses		
Cost of goods sold	719	455
Operation and maintenance	245	126
Depreciation and amortization	104	41
Taxes other than income taxes	64	13
Nicor merger expenses	10	5
Total operating expenses	1,142	640
Operating income	262	238
Other income	4	1
Interest expense, net	(47)	(29)
Earnings before income taxes	219	210
Income tax expense	80	76
Net income	139	134
Less net income attributable to the noncontrolling interest	9	10
Net income attributable to AGL Resources Inc.	$ 130	$ 124
Per common share data		
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 1.12	$ 1.60
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$ 1.11	$ 1.59
Cash dividends declared per common share	$ 0.36	$ 0.45
Weighted average number of common shares outstanding		
Basic	116.7	77.7
Diluted	117.0	78.0

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(UNAUDITED)

In millions	Three months ended March 31, 2012	2011
Net income	$ 139	$ 134
Other comprehensive income (loss), net of tax		
Retirement benefit plans		
Reclassification of losses and prior service costs to net periodic pension cost (net of income tax of $1 in 2012)	1	0
Retirement benefit plans, net	1	0
Cash flow hedges, net of tax		
Net derivative instrument losses arising during the period (net of income tax of $1 in 2012 and $1 in 2011)	(2)	(1)
Cash flow hedges, net	(2)	(1)
Other comprehensive loss, net of tax	(1)	(1)
Comprehensive income	138	133
Less comprehensive income attributable to noncontrolling interest	0	0
Comprehensive income attributable to AGL Resources Inc.	$ 138	$ 133

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(UNAUDITED)

	AGL Resources Inc. Shareholders								
	Common stock								
In millions, except per share amounts	Shares	Amount	Additional paid-in capital	Retained earnings	Accumulated other comprehensive loss	Treasury shares	Noncontrolling interest	Total
Balance as of December 31, 2010	**78.0**	**$ 391**	**$ 631**	**$ 943**	**$ (150)**	**$ (2)**	**$ 23**	**$1,836**
Net income	0.0	0	0	124	0	0	10	134
Other comprehensive loss	0.0	0	0	0	(1)	0	0	(1)
Dividends on common stock ($0.45 per share)	0.0	0	1	(35)	0	0	0	(34)
Distributions to noncontrolling interest	0.0	0	0	0	0	0	(16)	(16)
Benefit, dividend reinvestment and stock purchase plans	0.2	1	2	0	0	(2)	0	1
Purchase of treasury shares	0.0	0	0	0	0	(2)	0	(2)
Stock-based compensation expense (net of tax)	0.0	0	2	0	0	0	0	2
Balance as of March 31, 2011	**78.2**	**$ 392**	**$ 636**	**$ 1,032**	**$ (151)**	**$ (6)**	**$ 17**	**$1,920**

	AGL Resources Inc. Shareholders							
	Common stock							
In millions, except per share amounts	Shares	Amount	Additional paid-in capital	Retained earnings	Accumulated other comprehensive loss	Treasury shares	Noncontrolling interest	Total
Balance as of December 31, 2011	**117.0**	**$ 586**	**$ 1,989**	**$ 967**	**$ (217)**	**$ (7)**	**$ 21**	**$3,339**
Net income	0.0	0	0	130	0	0	9	139
Other comprehensive loss	0.0	0	0	0	(1)	0	0	(1)
Dividends on common stock ($0.36 per share)	0.0	0	0	(42)	0	0	0	(42)
Distributions to noncontrolling interest	0.0	0	0	0	0	0	(14)	(14)
Benefit, dividend reinvestment and stock purchase plans	0.2	1	3	0	0	(1)	0	3
Stock-based compensation expense (net of tax)	0.0	0	2	0	0	0	0	2
Balance as of March 31, 2012	**117.2**	**$ 587**	**$ 1,994**	**$ 1,055**	**$ (218)**	**$ (8)**	**$ 16**	**$3,426**

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

In millions	Three months ended March 31, 2012	Three months ended March 31, 2011
Cash flows from operating activities		
Net income	$ 139	$ 134
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	104	41
Change in derivative instrument assets and liabilities	15	48
Deferred income taxes	0	23
Changes in certain assets and liabilities		
Inventories, net of temporary LIFO liquidation	375	278
Receivables, other than energy marketing	119	28
Prepaid taxes	90	26
Energy marketing receivables and trade payables, net	56	107
Trade payables, other than energy marketing	(89)	(23)
Other – net	7	56
Net cash flow provided by operating activities	816	718
Cash flows from investing activities		
Expenditures for property, plant and equipment	(171)	(94)
Net cash flow used in investing activities	(171)	(94)
Cash flows from financing activities		
Net payments and borrowings of short-term debt	(591)	(707)
Dividends paid on common shares	(42)	(34)
Distribution to noncontrolling interest	(14)	(16)
Payment of senior notes	0	(300)
Payments of term loan facility	0	(150)
Proceeds from term loan facility	0	150
Issuance of senior notes	0	495
Other	4	(1)
Net cash flow used in financing activities	(643)	(563)
Net increase in cash and cash equivalents	2	61
Cash and cash equivalents at beginning of period	69	24
Cash and cash equivalents at end of period	$ 71	$ 85
Cash paid during the period for		
Interest	$ 54	$ 36
Income taxes	$ 0	$ 1

See Notes to Condensed Consolidated Financial Statements (Unaudited).

Glossary of Key Terms

AGL RESOURCES INC. AND SUBSIDIARIES NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 – Organization and Basis of Presentation

General

AGL Resources Inc. is an energy services holding company that conducts substantially all its operations through its subsidiaries. Unless the context requires otherwise, references to "we," "us," "our," the "company," or "AGL Resources" mean consolidated AGL Resources Inc. and its subsidiaries.

On December 9, 2011, we closed our merger with Nicor and created a combined company with increased scale and scope in the distribution, storage and transportation of natural gas. As such, the businesses acquired as part of the merger are included for 2012 but not 2011 in our unaudited Condensed Consolidated Financial Statements. See Note 3 for additional information.

In addition, as a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011, received a pro rata dividend for the stub period, accruing from November 19, 2011. The dividend payments made in February 2012 were reduced by this stub period dividend.

The December 31, 2011 Condensed Consolidated Statement of Financial Position data was derived from our audited financial statements, but does not include all disclosures required by GAAP. We have prepared the accompanying unaudited Condensed Consolidated Financial Statements under the rules and regulations of the SEC. In accordance with such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with GAAP. Our unaudited Condensed Consolidated Financial Statements reflect all adjustments of a normal recurring nature that are, in the opinion of management, necessary for a fair presentation of our financial results for the interim periods. You should read these unaudited Condensed Consolidated Financial Statements in conjunction with our Consolidated Financial Statements and related notes included in Item 8 of our 2011 Form 10-K.

Due to the seasonal nature of our business and other factors, our results of operations and our financial condition for the periods presented, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.

Basis of Presentation

Our unaudited Condensed Consolidated Financial Statements include our accounts, the accounts of our wholly owned subsidiaries, the accounts of our majority-owned and controlled subsidiaries and the accounts of our consolidated variable interest entity (VIE) for which we are the primary beneficiary. For unconsolidated entities that we do not control, but exercise significant influence over, we use the equity method of accounting and our proportionate share of income or loss is recorded in the unaudited Condensed Consolidated Statements of Income. See Note 8 for additional information. We have eliminated intercompany profits and transactions in consolidation except for intercompany profits where recovery of such amounts are probable under the affiliates' rate regulation process.

Certain amounts from prior periods have been reclassified and revised to conform to the current-period presentation. The reclassifications and revisions had no material impact on our prior period balances.

Note 2 – Significant Accounting Policies and Methods of Application

Our accounting policies are described in Note 2 to our Consolidated Financial Statements and related notes included in Item 8 of our 2011 Form 10-K. There were no significant changes to our accounting policies during the three months ended March 31, 2012.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures. Our estimates are based on historical experience and various other assumptions that we believe to be reasonable under the circumstances. We evaluate our estimates on an ongoing basis. Our estimates may involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates relate to our pipeline replacement program accruals, environmental liability accruals, uncollectible accounts and other allowance for contingent losses, goodwill and intangible assets, retirement plan benefit obligations, derivative and hedging activities and provisions for income taxes. Our actual results could differ from our estimates.

Investments

Our investments in debt and equity securities are as follows:

In millions	March 31, 2012	December 31, 2011	March 31, 2011
Money market funds	$ 68	$ 59	$ 0
Corporate bonds	8	6	0
Other investments	5	7	0
Total	$ 81	$ 72	$ 0

Investments in debt and equity securities are classified on the unaudited Condensed Consolidated Statements of Financial Position as follows:

In millions	March 31, 2012	December 31, 2011	March 31, 2011
Cash equivalents	$ 13	$ 9	$ 0
Short-term investments	57	53	0
Long-term investments	11	10	0
Total	$ 81	$ 72	$ 0

Investments categorized as trading (including money market funds) totaled $68 million at March 31, 2012 and $59 million at December 31, 2011.

Corporate bonds and certain other investments are categorized as held-to-maturity. The contractual maturities of the held-to-maturity investments at March 31, 2012 are as follows:

	Years to maturity			
In millions	Less than 1 year	1-5 years	5-10 years	Total
Held-to-maturity investments	$ 2	$ 6	$ 0	$ 8

Our investments also include certain investments, including certificates of deposit and bank accounts, maintained to fulfill statutory or contractual requirements. These investments totaled $1 million at March 31, 2012 and $3 million at December 31, 2011. Gains or losses included in earnings resulting from the sale of investments were not significant.

Inventories

Nicor Gas' inventory is carried at cost on a last-in-first-out (LIFO) basis. Inventory decrements occurring during interim periods that are expected to be restored prior to year-end are charged to cost of goods sold at the estimated annual replacement cost, and the difference between this cost and the actual LIFO layer cost is recorded as a temporary LIFO inventory liquidation. This is classified in other current liabilities on our unaudited Condensed Consolidated Statements of Financial Position. The inventory decrement as of March 31, 2012 is expected to be restored prior to year-end. Interim inventory decrements not expected to be restored prior to year-end are charged to cost of goods sold at the actual LIFO cost of the layers liquidated.

Our retail operations, wholesale services and midstream operations segments evaluate the weighted average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other-than-temporary. For any declines considered to be other-than-temporary, we record adjustments to reduce the weighted average cost of the natural gas inventory to market price. Consequently, as a result of declining natural gas prices during the three months ended March 31, 2012 and 2011, retail operations, wholesale services and midstream operations recorded LOCOM adjustments to cost of goods sold in the following amounts, to reduce the value of their inventories to market value.

In millions	2012	2011
Retail operations	$ 3	$ 0
Wholesale services	18	0
Midstream operations	1	0

Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail and wholesale marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements, which enable our wholesale services segment to net receivables and payables by counterparty. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The amounts due from or owed to wholesale services' counterparties are settled net, but are recorded on a gross basis in our unaudited Condensed Consolidated Statements of Financial Position as energy marketing receivables and energy marketing payables.

Our wholesale services segment has some trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, wholesale services would need to post collateral to continue transacting business with some of its counterparties. No collateral has been posted under such provisions since our credit ratings have always exceeded the minimum requirements. As of March 31, 2012, December 31, 2011 and March 31, 2011, the collateral that wholesale services would have been required to post if our credit ratings had been downgraded to non-investment grade status would not have had a material impact to our consolidated results of operations, cash flows or financial condition. However, if such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be negatively impacted.

Fair Value Measurements

We have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. The carrying values of cash and cash equivalents, short and long-term investments, derivative assets and liabilities, short-term debt, other current assets and liabilities and accrued interest approximate fair value. The nonfinancial assets and liabilities include pension and other retirement benefits, which are presented in Note 4 to our Consolidated Financial Statements and related notes included in Item 8 of our 2011 Form 10-K.

As defined in the authoritative guidance related to fair value measurements and disclosures, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observance of those inputs in accordance with the fair value hierarchy.

Natural Gas Derivative Instruments

The fair value of natural gas derivative instruments we use to manage exposures arising from changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all of our derivative instruments. See Note 5 for additional derivative disclosures.

Distribution Operations Nicor Gas, subject to review by the Illinois Commission, and Elizabethtown Gas, in accordance with a directive from the New Jersey BPU, enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices. In accordance with the authoritative guidance related to derivatives and hedging, such derivative transactions are accounted for at fair value each reporting period in our unaudited Condensed Consolidated Statements of Financial Position. In accordance with regulatory requirements realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. Thus, hedge accounting is not elected and, in accordance with accounting guidance pertaining to rate-regulated entities, unrealized changes in the fair value of these derivative instruments are deferred or accrued as regulatory assets or liabilities.

Nicor Gas also enters into swap agreements to reduce the earnings volatility of certain forecasted operating costs arising from fluctuations in natural gas prices, such as the purchase of natural gas for use in its operations. These derivative instruments are carried at fair value. To the extent hedge accounting is not elected, changes in such fair values are immediately recorded in the current period as operation and maintenance expense.

Retail Operations We have designated a portion of these derivative instruments, consisting of financial swaps to manage the risk associated with forecasted natural gas purchases and sales, as cash flow hedges under the authoritative guidance related to derivatives and hedging. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the settlement of the underlying hedged item.

We currently have minimal hedge ineffectiveness defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item. This cash flow hedge ineffectiveness is recorded in cost of goods sold in our unaudited Condensed Consolidated Statements of Income in the period in which it occurs. We have not designated the remainder of our derivative instruments as hedges under the authoritative guidance related to derivatives and hedging and, accordingly, we record changes in the fair value of such instruments within cost of goods sold in our Consolidated Statements of Income in the period of change.

We enter into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather in the Heating Season. We account for these contracts using the intrinsic value method under the authoritative guidance related to financial instruments. These weather derivative instruments do not qualify for accounting hedge designation and changes in value are reflected in cost of goods sold on our unaudited Condensed Consolidated Statements of Income.

Wholesale Services We purchase natural gas for storage when the difference in the current market price we pay to buy and transport natural gas plus the cost to store the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures contracts and other OTC derivatives to sell natural gas at that future price to substantially lock in the operating margin we will ultimately realize when the stored natural gas is sold. These futures contracts meet the definition of derivatives under the authoritative guidance related to derivatives and hedging and are accounted for at fair value in our Consolidated Statements of Financial Position, with changes in fair value recorded in our unaudited Condensed Consolidated Statements of Income in the period of change. These futures contracts are not designated as hedges as may be permitted under the guidance.

The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis we utilize for the derivatives used to mitigate the natural gas price risk associated with our storage portfolio. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Midstream Operations During the construction of our storage caverns, we use derivative instruments to reduce our exposure to the risk of changes in the price of natural gas that will be purchased in future periods for gas associated with bringing our facilities into service, including pad gas that is considered to be a component of the storage cavern's construction costs. We use derivative instruments to economically hedge operational and optimization purchases and sales and do not qualify as cash flow hedges.

We have designated as cash flow hedges, those derivative instruments executed to manage the risk with the purchase of pad gas. Any derivative gains or losses arising from the cash flow hedges will remain in accumulated OCI until the pad gas is sold, which will not occur until the storage caverns are decommissioned. The fair value of these derivative instruments currently have minimal hedge ineffectiveness which is recorded in cost of goods sold in our Consolidated Statements of Income in the period in which it occurs.

Earnings Per Common Share

We compute basic earnings per common share attributable to AGL Resources Inc. common shareholders by dividing our income attributable to AGL Resources Inc. by the daily weighted average number of common shares outstanding. Diluted earnings per common share attributable to AGL Resources Inc. common shareholders reflect the potential reduction in earnings per common share attributable to AGL Resources Inc. common shareholders that could occur when potentially dilutive common shares are added to common shares outstanding. The increase in weighted average shares is primarily due to the issuance of 38.2 million shares in connection with the Nicor merger.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The vesting of certain shares of the restricted stock and restricted stock units depends on the satisfaction of defined performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders for the periods presented, if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised:

	Three months ended March 31,	
In millions (except per share amounts)	**2012**	**2011**
Net income attributable to AGL Resources Inc.	$ 130	$ 124
Denominator:		
Basic weighted average number of shares outstanding (1)	116.7	77.7
Effect of dilutive securities	0.3	0.3
Diluted weighted average number of shares outstanding	117.0	78.0
Basic and diluted earnings per share		
Basic	$ 1.12	$ 1.60
Diluted	$ 1.11	$ 1.59

(1) Daily weighted average shares outstanding.

The following table contains the weighted average shares attributable to outstanding stock options that were excluded from the computation of diluted earnings per common share attributable to AGL Resources Inc. because their effect would have been anti-dilutive, as the exercise prices were greater than the average market price:

In millions	March 31, 2012	March 31, 2011
Three months ended	0.0	0.7

The decrease in the number of shares that were excluded from the computation for the three months ended March 31, 2012 is primarily the result of an increase in the average market value of our common shares compared to the same period during 2011.

Regulatory Assets and Liabilities

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs and estimated future expenditures that would otherwise be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs or expenditures will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have not yet been incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulatory commissions. We are not aware of any evidence that these costs will not be recoverable through either rate riders or base rates, and we believe that we will be able to recover these costs, consistent with our historical recoveries. In the event that the authoritative guidance related to regulated operations were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income, and be classified as an extraordinary item.

Our regulatory assets and liabilities are summarized in the following table.

In millions	March 31, 2012	December 31, 2011 (1)	March 31, 2011
Regulatory assets - current			
Recoverable regulatory infrastructure program costs	$ 48	$ 48	$ 49
Recoverable retirement benefit costs	29	29	0
Recoverable ERC	7	7	7
Other	53	47	17
Total regulatory assets - current	137	131	73
Regulatory assets - long-term			
Recoverable ERC	349	351	162
Recoverable regulatory infrastructure program costs	291	305	231
Recoverable retirement benefit costs	256	262	9
Unamortized losses on reacquired debt	21	21	10
Other	140	140	22
Total regulatory assets - long-term	1,057	1,079	434
Total regulatory assets	$ 1,194	$ 1,210	$ 507
Regulatory liabilities - current			
Accrued natural gas costs	$ 97	$ 53	$ 51
Bad debt rider	32	30	0
Accumulated removal costs	14	14	0
Other	30	15	26
Total regulatory liabilities - current	173	112	77
Regulatory liabilities - long-term			
Accumulated removal costs	1,339	1,321	250
Unamortized investment tax credit	32	32	11
Regulatory income tax liability	26	27	15
Bad debt rider	20	14	0
Other	14	11	20
Total regulatory liabilities - long-term	1,431	1,405	296
Total regulatory liabilities	$ 1,604	$ 1,517	$ 373

(1) The increase in regulatory assets and liabilities from March 31, 2011, includes $545 million related to the addition of Nicor Gas' regulatory assets and includes $1,330 million related to the addition of Nicor Gas' regulatory liabilities.

As of March 31, 2012, there have been no new types of regulatory assets or liabilities from those discussed in Note 2 to our Consolidated Financial Statements and related notes in Item 8 of our 2011 Form 10-K.

Accounting Developments

On January 1, 2012, we adopted authoritative guidance related to fair value measurements. The guidance expands the qualitative and quantitative disclosures for Level 3 significant unobservable inputs, permits the use of premiums and discounts to value an instrument if it is standard practice. The guidance also limits the application of best use valuation to non-financial assets and liabilities. This guidance had no impact on our unaudited Condensed Consolidated Financial Statements. See Note 4 for additional fair value disclosures.

On January 1, 2012, we adopted authoritative guidance related to comprehensive income. The guidance eliminates the option to present other comprehensive income in the unaudited Condensed Consolidated Statements of Equity, but allows companies to elect to present net income and other comprehensive income in one continuous statement (unaudited Condensed Consolidated Statements of Comprehensive Income) or in two consecutive statements. This guidance does not change any of the components of net income or other comprehensive income and earnings per share will still be calculated based on net income. This guidance did not have a material impact on our unaudited Condensed Consolidated Financial Statements.

Note 3 – Merger with Nicor

On December 9, 2011, we completed our $2.5 billion merger with Nicor. The preliminary allocation of the total consideration transferred in the merger to the fair value of assets acquired and liabilities assumed included adjustments for the fair value of Nicor's assets and liabilities. The preliminary allocation of the purchase price is presented in the following table.

In millions	
Current assets	$ 932
Property, plant and equipment	3,202
Goodwill	1,395
Other noncurrent assets, excluding goodwill	791
Current liabilities	(1,170)
Long-term debt	(599)
Other noncurrent liabilities	(2,048)
Total purchase consideration	$ 2,503

The estimated fair values of the assets acquired and the liabilities assumed were determined based on the accounting guidance for fair value measurements under GAAP, which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The estimated fair value measurements assume the highest and best use of the assets by market participants, considering the use of the asset that is physically possible, legally permissible and financially feasible at the measurement date. Modifications to the purchase price allocation may occur as a result of continuing review of the assumptions and estimates underlying the preliminary fair value adjustments of environmental site remediation and other adjustments.

We concluded that net book value is a reasonable estimate of fair value for Nicor's tangible and intangible assets and liabilities that are explicitly subject to cost-of-service ratemaking. The company determined the fair value of Nicor's long-term debt using the income approach, and used a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. As a result, our purchase price allocation included an adjustment of $99 million to step-up the basis of Nicor's long-term debt to fair value as of the merger date. A corresponding regulatory asset was recorded in connection with the fair value adjustment of the debt. While the regulatory asset related to debt is not included in rate base, the costs are recovered over the term of the debt through the authorized rate of return component of base rates. The following table summarizes our purchase price allocation for Nicor Gas' regulatory assets and liabilities.

In millions	
Current assets	$ 36
Other noncurrent assets, excluding goodwill	477
Current liabilities	(80)
Other noncurrent liabilities	(1,137)

For all other assets and liabilities acquired from Nicor, we considered the income, market and cost approaches to fair valuation. The income approach estimates the fair value by discounting the projected future cash flows at our weighted average cost of capital. We utilized this approach to obtain the business enterprise values for each reporting unit. Additionally, we used the income approach to determine the fair values for intangible trade names and customer relationships assets.

The market approach is based on the premise that the fair value can be determined through the use of prices and other relevant information generated by the market transactions involving identical or comparable assets or liabilities. Finally, the cost approach utilizes the concept of replacement cost as an indicator of fair value. We applied the market and cost approach to estimate the fair value of the property, plant and equipment. Our valuations included a $31 million step-up for Nicor's non-regulatory property, plant and equipment. This was primarily related to the vessels and related equipment at our cargo shipping segment.

The excess of the purchase price paid over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill, which is not deductible for tax purposes. A preliminary rollforward of total goodwill recognized by segment in our unaudited Condensed Consolidated Statements of Financial Position is as follows:

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other	Consolidated
As of December 8, 2011	$ 404	$ 0	$ 0	$ 14	$ 0	$ 0	$ 418
Merger with Nicor	1,182	124	2	2	77	8	1,395
As of March 31, 2012	$ 1,586	$ 124	$ 2	$ 16	$ 77	$ 8	$ 1,813

The preliminary valuation of the additional intangible assets recorded as result of the merger is as follows:

In millions	Preliminary valuation	Weighted average amortization period
Trade names:		
Retail operations	$ 33	15 years
Cargo shipping	15	15 years
Customer relationships:		
Retail operations	52	10 years
Cargo shipping	3	18 years
Total	$ 103	

The fair value measurements of intangible assets were primarily based on significant unobservable inputs and represent Level 3 measurements as defined in accounting guidance for fair value measurements.

The following table summarizes the estimated fair value of the acquired receivables recorded in connection with the merger:

In millions	
Nicor accounts receivable at December 9, 2011	$400
Cash flows not expected to be collected	24
Fair value of acquired receivables	$376

In connection with the merger, AGL Resources recorded merger transaction costs of $10 million ($6 million net of tax) for the three months ended March 31, 2012 compared to $5 million ($3 million net of tax) incurred by AGL Resources for the same period in 2011. These costs were expensed as incurred.

Pro forma financial information The following unaudited pro forma financial information reflects our consolidated results of operations as if the merger with Nicor had taken place on January 1, 2011. The unaudited pro forma information has been calculated after conforming our accounting policies and adjusting Nicor's results to reflect the depreciation and amortization that would have been charged assuming fair value adjustments to property, plant and equipment, debt and intangible assets had been applied on January 1, 2011, together with the consequential tax effects.

AGL Resources and Nicor together incurred approximately $86 million in the twelve months ended December 31, 2011 and $7 million in the three months ended March 31, 2011. These expenses are excluded from the pro forma earnings presented below.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the pro forma events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

In millions, except per share amounts	Twelve months ended December 31, 2011	Three months ended March 31, 2011
Total revenues	$ 4,715	$ 1,915
Net income attributable to AGL Resources Inc.	$ 313	$ 165
Basic earnings per common share	$ 2.69	$ 1.42
Diluted earnings per common share	$ 2.68	$ 1.42

Note 4 – Fair Value Measurements

The methods used to determine the fair value of our assets and liabilities are described within Note 2 – Significant Accounting Policies and Methods of Application.

Derivative Instruments

The following table summarizes, by level within the fair value hierarchy, our derivative assets and liabilities that were accounted for at fair value on a recurring basis as of the periods presented. See Note 5 – Derivative Instruments for additional derivative instrument information.

	Recurring fair values Derivative instruments					
	March 31, 2012		December 31, 2011		March 31, 2011	
In millions	**Assets**	**Liabilities**	**Assets** (1)	**Liabilities**	**Assets** (1)	**Liabilities**
Natural gas derivatives						
Quoted prices in active markets (Level 1)	$ 7	$ (187)	$ 11	$ (145)	$ 1	$ (63)
Significant other observable inputs (Level 2)	203	(68)	229	(68)	101	(15)
Netting of cash collateral	47	162	32	115	38	50
Total carrying value (2) (3)	**$ 257**	**$ (93)**	**$ 272**	**$ (98)**	**$ 140**	**$ (28)**
Interest rate derivatives						
Significant other observable inputs (Level 2)	**$ 9**	**$ (10)**	**$ 13**	**$ (13)**	**$ 0**	**$ 0**

(1) Less than $1 million at March 31, 2011 and $3 million at December 31, 2011 associated with weather derivatives have been excluded as they are accounted for based on intrinsic value.
(2) There were no material unobservable inputs (Level 3) for any of the periods presented.
(3) There were no material transfers between Level 1, Level 2, or Level 3 for any of the periods presented.

Money Market Funds

In millions	**March 31, 2012**	**December 31, 2011**	**March 31, 2011**
Money market funds (1)	$ 68	$ 59	$ 0

(1) Recorded at fair value and classified as Level 1 within the fair value hierarchy.

Debt

Our long-term debt is recorded at amortized cost, with the exception of Nicor Gas' first mortgage bonds, which are recorded at acquisition date fair value. We estimate the fair value of our debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. The following table presents the amortized cost and fair value of our long-term debt as of the following periods.

In millions	**March 31, 2012**	**December 31, 2011**	**March 31, 2011**
Long-term debt amortized cost (1)	$ 3,573	$ 3,576	$ 2,173
Long-term debt fair value (1) (2)	$ 3,922	$ 3,938	$ 2,304

(1) March 31, 2012 and December 31, 2011 include $15 million of medium-term notes that are due in 2012 and the debt that was assumed in the Nicor merger with a carrying value of $500 million.
(2) Valued using Level 2 inputs.

Note 5 – Derivative Instruments

Certain of our derivative instruments contain credit-risk-related or other contingent features that could increase the payments for collateral we post in the normal course of business when our financial instruments are in net liability positions. As of March 31, 2012 for agreements with such features, derivative instruments with liability fair values totaled approximately $103 million for which we had posted no collateral to our counterparties. In addition, our energy marketing receivables and payables, which also have credit-risk-related or other contingent features, are discussed in Note 2. Our derivative instrument activities are included within operating cash flows as an adjustment to net income and were $15 million for the three months ended March 31, 2012 and $48 million for the three months ended March 31, 2011. See Note 4 – Fair Value Measurements for additional derivative instrument information.

The following table summarizes the various ways in which we account for our derivative instruments and the impact on our Consolidated Financial Statements:

	Recognition and Measurement	
Accounting Treatment	**Statement of Financial Position**	**Income Statement**
Cash flow hedge	Derivative carried at fair value	Ineffective portion of the gain or loss on the derivative instrument is recognized in earnings
	Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss)	Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated OCI (loss) and into earnings when the forecasted transaction affects earnings
Fair value hedge	Derivative carried at fair value Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	Gains or losses on the derivative instrument and the hedged item are recognized in earnings. As a result, to the extent the hedge is effective, the gains or losses will offset and there is no impact on earnings. Any hedge ineffectiveness will impact earnings.
Not designated as hedges	Derivative carried at fair value	Realized and unrealized gains or losses on the derivative instrument are recognized in earnings
	Distribution operations' gains and losses on derivative instruments are deferred as regulatory assets or liabilities until included in natural gas costs	The gain or loss on these derivative instruments is reflected in natural gas costs and is ultimately included in billings to customers

Distribution Operations

Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities respectively within our unaudited Condensed Consolidated Statements of Financial Position until recovered from customers. The following amounts represent realized losses incurred for the three months ended March 31.

In millions	**2012**	**2011**
Nicor Gas	$ 1	n/a
Elizabethtown Gas	$ 9	$ 8

Quantitative Disclosures Related to Derivative Instruments

As of the periods presented, our derivative instruments were comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. We had net long natural gas contracts outstanding in the following quantities:

Natural gas contracts *In Bcf*	**March 31, 2012** (1) (2)	**December 31, 2011** (2)	**March 31, 2011**
Hedge designation:			
Cash flow	7	5	3
Not designated	116	186	278
Total	123	191	281
Hedge position:			
Short	(1,942)	(1,680)	(1,617)
Long	2,065	1,871	1,898
Net long position	123	191	281

(1) Approximately 98% of these contracts have durations of two years or less and the remaining 2% expire in 3 to 6 years.
(2) Volumes related to Nicor Gas exclude variable-priced contracts, which are accounted for as derivatives, but whose fair values are not directly impacted by changes in commodity prices.

Derivative Instruments on the Unaudited Condensed Consolidated Statements of Financial Position

The following table presents the fair value and unaudited Condensed Consolidated Statements of Financial Position classification of our derivative instruments as of the periods presented:

In millions Unaudited Condensed Consolidated Statements of Financial Position location (1) (2)		March 31, 2012	December 31, 2011	March 31, 2011
Designated as cash flow and fair value hedges				
Asset Instruments				
Current natural gas contracts	Derivative instruments assets and liabilities – current portion	$ 5	$ 9	$ 1
Interest rate swap agreements	Derivative instruments assets – long-term portion	9	13	0
Liability Instruments				
Current natural gas contracts	Derivative instruments assets and liabilities – current portion	(11)	(12)	(2)
Interest rate swap agreements	Derivative instruments liabilities – long-term portion	(11)	(13)	0
Total		(8)	(3)	(1)
Not designated as cash flow hedges				
Asset Instruments				
Current natural gas contracts	Derivative instruments assets and liabilities – current portion	683	706	333
Noncurrent natural gas contracts	Derivative instruments assets and liabilities	82	133	77
Liability Instruments				
Current natural gas contracts	Derivative instruments assets and liabilities – current portion	(718)	(689)	(323)
Noncurrent natural gas contracts	Derivative instruments assets and liabilities	(85)	(116)	(62)
Total		(38)	34	25
Total derivative instruments		$ (46)	$ 31	$ 24

(1) These amounts are netted within our unaudited Condensed Consolidated Statements of Financial Position for amounts which we have netting arrangements with the counterparties.

(2) As required by the authoritative guidance related to derivatives and hedging, the fair value amounts are presented on a gross basis. As a result, the amounts do not include cash collateral held on deposit in broker margin accounts of $209 million as of March 31, 2012, $147 million as of December 31, 2011 and $88 million as of March 31, 2011. Accordingly, these amounts will differ from the amounts presented on our unaudited Condensed Consolidated Statements of Financial Position and the fair value information presented for our derivative instruments in the recurring fair values table of Note 4.

Derivative Instruments on the Unaudited Condensed Consolidated Statements of Income

The following table presents the gain or (loss) on derivative instruments in our unaudited Condensed Consolidated Statements of Income for the three months ended March 31, 2012 and 2011:

In millions	2012	2011
Designated as cash flow hedges		
Natural gas contracts – loss reclassified from OCI into cost of goods sold for settlement of hedged item	$ (1)	$ 0
Interest rate swaps – ineffectiveness recorded as an offset to interest expense	2	0
Not designated as hedges		
Natural gas contracts – fair value adjustments recorded in operating revenues (1)	4	11
Natural gas contracts – net gain fair value adjustments recorded in cost of goods sold (2)	(2)	(1)
Natural gas contracts – net loss fair value adjustments recorded in operation and maintenance expense	(1)	0
Total gains on derivative instruments	$ 2	$ 10

(1) Associated with the fair value of existing derivative instruments at March 31, 2012 and 2011.

(2) Excludes losses recorded in cost of goods sold associated with weather derivatives of $14 million for the three months ended March 31, 2012 and gains of $3 million for the three months ended March 31, 2011.

Any amounts recognized in operating income, related to ineffectiveness or due to a forecasted transaction that is no longer expected to occur, were immaterial for the three months ended March 31, 2012 and 2011.

Our expected net loss to be reclassified from OCI into cost of goods sold, operation and maintenance expense, and operating revenues and recognized in our unaudited Condensed Consolidated Statements of Income over the next 12 months is $8 million. These pre-tax deferred losses are recorded in OCI related to natural gas derivative contracts. The expected losses are based upon the fair values of these financial instruments at March 31, 2012.

There have been no other significant changes to our derivative instruments, as described in Note 2 and Note 4 to our Consolidated Financial Statements and related notes included in Item 8 of our 2011 Form 10-K.

Note 6 - Employee Benefit Plans

Pension Benefits

We sponsor three tax-qualified defined benefit retirement plans for our eligible employees, the Nicor Gas Retirement Plan, the AGL Retirement Plan and the NUI Retirement Plan. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant. Following are the combined cost components of our three defined benefit pension plans for the periods indicated:

	Three months ended March 31,	
In millions	2012	2011
Service cost	$ 7	$ 3
Interest cost	11	7
Expected return on plan assets	(16)	(8)
Net amortization of prior service cost	(1)	(1)
Recognized actuarial loss	9	4
Net pension benefit cost	$ 10	$ 5

Other Defined Benefit Retirement Benefits

We sponsor two defined benefit retirement health care plans for our eligible employees, the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan) and the Nicor Gas Welfare Benefit Plan. Eligibility for these benefits is based on age and years of service.

Following are the cost components of our other retirement benefit costs for the periods indicated:

	Three months ended March 31,	
In millions	2012	2011
Service cost	$ 1	$ 0
Interest cost	4	1
Expected return on plan assets	(1)	(1)
Net amortization of prior service cost	(1)	(1)
Recognized actuarial loss	3	1
Net benefit cost	$ 6	$ 0

Contributions

Our employees generally do not contribute to these pension and other retirement plans, however, Nicor Gas and AGL Resources pre-65 retirees make nominal contributions to their health care plan. We fund the qualified pension plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. As required by The Pension Protection Act of 2006 (the Act), we calculate the minimum amount of funding using the traditional unit credit cost method.

The Act contained new funding requirements for single employer defined benefit pension plans and established a 100% funding target (over a 7-year amortization period) for plan years beginning after December 31, 2007. If certain conditions were met, the Worker, Retiree and Employer Recovery Act of 2008 allowed us to measure our required minimum contributions based on a funding target of 100% in 2011 and 2012. In the first three months of 2012 we contributed $17 million to the AGL Retirement Plan and the NUI Retirement Plan and $38 million during the same period last year. For more information on our pension plans, see Note 11 to our Consolidated Financial Statements and related notes included in Item 8 of our 2011 Form 10-K.

Note 7 - Debt

The following table provides maturity dates, year-to-date weighted average interest rates and amounts outstanding for our various debt securities and facilities that are included in our unaudited Condensed Consolidated Statements of Financial Position. For additional information on our debt see Note 7 in our Consolidated Financial Statements and related notes in Item 8 of our 2011 Form 10-K.

	March 31, 2012				March 31, 2011	
Dollars in millions	**Year(s) due**	**Weighted average interest rate** (1)	**Outstanding**	**Outstanding at December 31, 2011**	**Weighted average interest rate** (1)	**Outstanding**
Short-term debt						
Commercial paper- AGL Capital	2012	0.5%	$ 625	$ 869	0.4%	$ 25
Commercial paper- Nicor Gas	2012	0.5	105	452	n/a	n/a
Current portion of long-term debt	2012	8.3	15	15	n/a	0
Current portion of capital leases	2012	4.9	2	2	4.9	1
Total short-term debt and current portion of long-term debt and capital leases		**0.6%**	**$ 747**	**$ 1,338**	**0.4%**	**$ 26**
Long-term debt – excluding current portion						
Senior notes	2013-2041	5.1%	$ 2,550	$ 2,550	5.5%	$ 1,775
First mortgage bonds	2016-2038	5.6	500	500	n/a	n/a
Gas facility revenue bonds	2022-2033	1.1	200	200	1.2	200
Medium-term notes	2017-2027	7.8	181	181	7.8	196
Capital leases	2012	n/a	0	0	4.9	2
Total principal long-term debt		4.9%	$ 3,431	$ 3,431	5.3%	$ 2,173
First mortgage bonds fair value adjustment	2016-2038	n/a	$ 97	$ 99	n/a	n/a
Interest rate swaps fair value adjustment	2016	n/a	12	13	n/a	0
Unamortized debt premium (discount), net	-	n/a	18	18	n/a	n/a
Total non-principal long-term debt		n/a	$ 127	$ 130	n/a	$ 0
Total long-term debt			**$ 3,558**	**$ 3,561**		**$ 2,173**
Total debt			**$ 4,305**	**$ 4,899**		**$ 2,199**

(1) Interest rates are calculated based on the daily average balance outstanding.

Financial and Non-Financial Covenants

The AGL Credit Facility and the Nicor Gas Credit Facility each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. These ratios, as calculated in accordance with the debt covenants include standby letters of credit and surety bonds and exclude OCI pension adjustments. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the periods presented.

	March 31, 2012	December 31, 2011	March 31, 2011
AGL Credit Facility	54%	58%	51%
Nicor Gas Credit Facility	47%	60%	n/a

The credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations and other matters customarily restricted in such agreements.

Default Provisions

Our credit facilities and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. The most important default events include:

- a maximum leverage ratio
- insolvency events and nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We have no triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other triggering events. We are in compliance with all existing debt provisions and covenants, both financial and non-financial, as of March 31, 2012 and 2011.

Note 8 – Non-Wholly Owned Entity

As of March 31, 2012, we had ownership interests in SouthStar, Triton, Horizon Pipeline and Sawgrass Storage.

Variable Interest Entities

On a quarterly basis we evaluate all of our owner interests to determine if they represent a VIE as defined by the authoritative accounting guidance on consolidation, and if so, which party is the primary beneficiary. We have determined that SouthStar, a joint venture owned by us and Piedmont, is the only VIE for which we are the primary beneficiary, which requires us to consolidate its assets, liabilities and Statements of Income. See Note 10 to our Consolidated Financial Statements and related notes included in Item 8 of our 2011 Form 10-K. Earnings from SouthStar in 2012 and 2011 were allocated entirely in accordance with the ownership interests.

SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers primarily in Georgia, and under various other trade names to retail customers in Ohio, Florida and New York and to commercial and industrial customers, principally in Alabama, Florida, North Carolina, South Carolina and Tennessee.

During the three months ended March 31, 2012, there have been no significant changes to the primary risks associated with SouthStar as discussed in our risk factors included in Item 1A of our 2011 Form 10-K.

SouthStar's financial results are seasonal in nature, with business depending to a great extent on the first and fourth quarters of each year. SouthStar's current assets consist primarily of natural gas inventory, derivative instruments and receivables from its customers. SouthStar also has receivables from us due to its participation in AGL Capital's commercial paper program. See Note 2 for additional discussions of SouthStar's inventories. SouthStar's restricted assets consist of customer deposits and were immaterial as of March 31, 2012 and 2011. SouthStar's current liabilities consist primarily of accrued natural gas costs, other accrued expenses, customer deposits, derivative instruments and payables to us from its participation in AGL Capital's commercial paper program.

SouthStar's other contractual commitments and obligations, including operating leases and agreements with third party providers, do not contain terms that would trigger material financial obligations in the event that such contracts were terminated. As a result, our maximum exposure to a loss at SouthStar is considered to be immaterial. SouthStar's creditors have no recourse to our general credit beyond our corporate guarantees we have provided to SouthStar's counterparties and natural gas suppliers. We have provided no financial or other support that was not previously contractually required. With the exception of our corporate guarantees, we have not entered into any arrangements that could require us to provide financial support to SouthStar.

Price and volume fluctuations of SouthStar's natural gas inventories can cause significant variations in our working capital and cash flow from operations. Changes in our operating cash flows are also attributable to SouthStar's working capital changes resulting from the impact of weather, the timing of customer collections, payments for natural gas purchases and cash collateral amounts that SouthStar maintains to facilitate its derivative instruments.

Cash flows used in our investing activities include capital expenditures of $1 million and $1 million for SouthStar for the three months ended March 31, 2012 and 2011, respectively and $2 million for the year ended December 31, 2011. Cash flows used in our financing activities include SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year. Generally, this distribution occurs in the first or second quarter of each fiscal year. For the three months ended March 31, 2012, SouthStar distributed $14 million to Piedmont and $16 million during the same period last year. The decrease of $2 million was primarily the result of decreased earnings year-over-year.

The following table provides additional information for the dates presented, which are consolidated within our unaudited Condensed Consolidated Statements of Financial Position.

	March 31, 2012			December 31, 2012			March 31, 2011		
In millions	**Consolidated**	**SouthStar** (1)	% (2)	**Consolidated**	**SouthStar** (1)	%(2)	**Consolidated**	**SouthStar** (1)	% (2)
Current assets	$ 2,022	$ 149	7%	$ 2,746	$ 210	8%	$ 1,587	$ 170	11%
Long-term assets and other deferred debits	11,217	9	0	11,167	9	0	5,439	9	0
Total assets	$ 13,239	$ 158	1%	$ 13,913	$ 219	2%	$ 7,026	$ 179	3%
Current liabilities	$ 2,348	$ 52	2%	$ 3,084	$ 77	2%	$ 1,313	$ 61	5%
Long-term liabilities and other deferred credits	7,465	0	0	7,490	0	0	3,793	0	0
Total Liabilities	9,813	52	1	10,574	77	1	5,106	61	1
Equity	3,426	106	3	3,339	142	4	1,920	118	6
Total liabilities and equity	$ 13,239	$ 158	1%	$ 13,913	$ 219	2%	$ 7,026	$ 179	3%

(1) These amounts reflect information for SouthStar and do not include intercompany eliminations or the balances of our wholly owned subsidiary with an 85% ownership interest in SouthStar.
(2) SouthStar's percentage of the amount on our unaudited Condensed Consolidated Statements of Financial Position.

The following table provides additional information on SouthStar's revenues and expenses for the three months ended March 31, 2012 and 2011, which are consolidated within our unaudited Condensed Consolidated Statements of Income.

In millions	**2012**	**2011**
Operating revenues	$ 215	$ 290
Operating expenses		
Cost of goods sold	133	200
Operation and maintenance	19	20
Depreciation and amortization	0	1
Taxes other than income taxes	1	0
Total operating expenses	153	221
Operating income	$ 62	$ 69

Equity Method Investments

Income from our equity method investments is classified as other income on our unaudited Condensed Consolidated Statements of Income. For the three months ended March 31, 2012, this included investment income from Triton of $3 million and an immaterial amount of investment income from our other equity method investments. For more information about our equity method investments, see Note 10 to our Consolidated Financial Statements under Item 8 included in our 2011 Form 10-K.

Note 9 - Commitments, Guarantees and Contingencies

There were no significant changes to our contractual obligations described in Note 11 of our Consolidated Financial Statements and related notes as filed in Item 8 of our 2011 Form 10-K.

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities.

Substitute Natural Gas

In 2011, Illinois enacted laws that required Nicor Gas and other large utilities in Illinois to elect to either sign contracts to purchase SNG from coal gasification plants to be constructed in Illinois or instead file rate cases with the Illinois Commission in 2012, 2014 and 2016.

On September 30, 2011, Nicor Gas signed an agreement to purchase approximately 25 Bcf of SNG annually for a 10-year term beginning as early as 2015. The counterparty intends to construct a 60 Bcf per year coal gasification plant in southern Illinois. The price of the SNG could significantly exceed market prices and is dependent upon a variety of factors. However, currently under the provisions of this contract the price could potentially be $9.95 per Mcf or more. The project is also expected to be financed by the counterparty with external debt and equity. This agreement complies with an Illinois statute that authorizes full recovery of the purchase costs; therefore we expect to recover such costs. Since the purchase agreement is contingent upon various milestones to be achieved by the counterparty to the agreement, our obligation is not certain at this time. The contract automatically terminates if construction does not commence by July 1, 2012. While the purchase agreement is a variable interest in the counterparty, we have concluded, based on a qualitative evaluation, that we are not the primary beneficiary required to consolidate the counterparty because we had no power to dictate the key terms of this agreement and we have no power to direct any of the activities of the seller. No amount has been recognized on our unaudited Condensed Consolidated Statements of Financial Position in connection with the purchase agreement.

Additionally, on October 11, 2011, the Illinois Power Agency (IPA) approved the form of a draft 30-year contract for the purchase by Nicor Gas of approximately 20 Bcf per year of SNG from a second proposed plant beginning as early as 2018. In November 2011, we filed a lawsuit against the IPA and the developer of this second proposed plant contending that the draft contract approved by the IPA does not conform to certain requirements of the enabling legislation. The lawsuit is pending in circuit court in DuPage County, Illinois. In accordance with the enabling legislation, the draft contract approved by the IPA for the second proposed plant was submitted to the Illinois Commission for further approvals by that regulatory body. The Illinois Commission issued an order on January 10, 2012 approving a final form of the contract for the second plant. The final form of contract approved by the Illinois Commission modified the draft contract submitted by the IPA in various respects. Both we and the developer of the plant filed applications for a rehearing with the Illinois Commission seeking changes to the final form of the contract. The Illinois Commission agreed to grant a rehearing on this contract and is expected to issue its ruling during the second quarter of 2012.

The purchase price of the SNG that may be produced from both of the coal gasification plants may significantly exceed market prices for natural gas and is dependent upon a variety of factors, including plant construction costs and volumes sold, and is currently unknown. The Illinois laws provide that prices paid for SNG purchased from the plants are to be considered prudent and not subject to review or disallowance by the Illinois Commission. As such, Illinois law effectively requires Nicor Gas' customers to provide subordinated financial support to the developers.

Contingencies and Guarantees

Contingent financial commitments, such as financial guarantees, represent obligations that become payable only if certain predefined events occur and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. We have certain subsidiaries that enter into various financial and performance guarantees and indemnities providing assurance to third parties. We believe the likelihood of payment under our guarantees and indemnities is remote. No liability has been recorded for such guarantees and indemnifications.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. The following table provides more information on the costs related to remediation of our former operating sites.

In millions	Cost estimate range	Amount recorded	Expected costs over next twelve months
Illinois	$ 136 - $218	$ 136	$ 21
Georgia and Florida	42 - 98	57	7
New Jersey	124 - 174	124	9
North Carolina	10 - 16	11	2
Total	$ 312 - $506	$ 328	$ 39

Our ERC liabilities are estimates of future remediation costs for our former operating sites that are contaminated. Our estimates are based on probabilistic models of potential costs and on an undiscounted basis. However, we have not yet performed these probabilistic models for all of our sites in Illinois, which will be completed in 2012. The results of detailed site-by-site investigations will determine the extent additional remediation is necessary and provide a basis for estimating additional future costs. For more information on our environmental remediation costs, see Note 2 herein and Note 11 of our Consolidated Financial Statements and related notes as filed in Item 8 of our 2011 Form 10-K.

Litigation

We are involved in litigation arising in the normal course of business. Although in some cases the company is unable to estimate the amount of loss reasonably possible in addition to any amounts already recognized, it is possible that the resolution of these contingencies, either individually or in aggregate, will require the company to take charges against, or will result in reductions in, future earnings. It is the opinion of management that the resolution of these contingencies, either individually or in aggregate, could be material to earnings in a particular period but will not have a material adverse effect on our consolidated financial position or cash flows. For additional litigation information, see Note 11 in our Consolidated Financial Statements and related notes in Item 8 of our 2011 Form 10-K.

PBR Proceeding Nicor Gas' PBR plan for natural gas costs went into effect in 2000 and was terminated January 1, 2003. Under this plan, Nicor Gas' total gas supply costs were compared to a market-sensitive benchmark. Savings and losses relative to the benchmark were determined annually and shared equally with sales customers. The PBR plan is currently under review by the Illinois Commission as there are allegations that Nicor Gas acted improperly in connection with the PBR plan. On June 27, 2002, the Citizens Utility Board (CUB) filed a motion to reopen the record in the Illinois Commission's proceedings to review the PBR plan. As a result of the motion to reopen, Nicor Gas, the staff of the Illinois Commission and CUB entered into a stipulation providing for additional discovery. The Illinois Attorney General's Office (IAGO) has also intervened in this matter. In addition, the IAGO issued Civil Investigation Demands (CIDs) to CUB and the Illinois Commission staff. The CIDs ordered that CUB and the Illinois Commission staff produce all documents relating to any claims that Nicor Gas may have presented, or caused to be presented, regarding false information related to its PBR plan. The staff of the Illinois Commission, IAGO and CUB submitted direct testimony to the Illinois Commission in April 2009 and rebuttal testimony in October 2011. In rebuttal testimony, the staff of the Illinois Commission, IAGO and CUB requested refunds of $85 million, $255 million and $305 million, respectively. We have committed to cooperate fully in the reviews of the PBR plan.

In February 2012, we committed to a stipulated resolution of issues with the staff of the Illinois Commission, which includes crediting Nicor Gas customers $64 million, but does not constitute an admission of fault. This liability is reflected in our unaudited Condensed Consolidated Statements of Financial Position at March 31, 2012 and December 31, 2011. The stipulated resolution is not final and is subject to review and approval by the Illinois Commission. CUB and IAGO are not parties to the stipulated resolution and continue to pursue their claims in this proceeding. Evidentiary hearings before the Administrative Law Judge were held during the first quarter of 2012 and post trial legal briefs from the parties are being submitted during the second quarter of 2012. Following the submission of legal briefs, the Administrative Law Judges will issue a proposed decision. There is no date scheduled for the issuance of that proposed decision.

We are unable to predict the outcome of the Illinois Commission's review or our potential exposure. Since the PBR plan and historical gas costs are still under Illinois Commission review, the final outcome could be materially different than the amounts reflected in our financial statements as of March 31, 2012.

Other We are also involved in service warranty product actions and municipal tax matters. While we are unable to predict the outcome of these matters or to reasonably estimate our potential exposure related thereto, if any, and have not recorded a liability associated with these contingencies, the final disposition of these matters is not expected to have a material adverse impact on our liquidity or financial condition. For additional litigation information on these matters, see Note 11 in our Consolidated Financial Statements and related notes in Item 8 of our 2011 Form 10-K.

In addition to the matters set forth above, we are involved with legal or administrative proceedings before various courts and agencies with respect to general claims, taxes, environmental, gas cost prudence reviews and other matters. Although we are unable to determine the ultimate outcome of these other contingencies, we believe that these amounts are appropriately reflected in our financial statements, including the recording of appropriate liabilities when reasonably estimable.

Note 10 – Segment Information

Our operating segments have changed as a result of our merger with Nicor and amounts from prior periods have been reclassified between the segments to reflect these changes. Our first quarter 2012 results include the activity of the Nicor legacy companies whereas our first quarter 2011 results do not. Our operating segments comprise revenue-generating components of our company for which we produce separate financial information internally that we regularly use to make operating decisions and assess performance. Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. We manage our businesses through five operating segments – distribution operations, retail operations, wholesale services, midstream operations, cargo shipping and one non-operating segment, other.

Our distribution operations segment is the largest component of our business and includes natural gas local distribution utilities in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland. These utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Although the operations of our distribution operations segment are geographically dispersed, the operating subsidiaries within the distribution operations segment are regulated utilities, with rates determined by individual state regulatory commissions. These natural gas distribution utilities have similar economic and risk characteristics.

We are also involved in several related and complementary businesses. Our retail operations segment includes retail natural gas marketing to end-use customers primarily in Georgia as well as various businesses that market retail energy-related products and services to residential and small business customers in Illinois. Additionally, our retail operations segment provides warranty protection solutions to customers and customer move connection services for utilities. Our wholesale services segment includes natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies, natural gas storage arbitrage and related activities. Our midstream operations segment includes the development and operation of high-deliverability natural gas storage assets.

Our cargo shipping segment transports containerized freight between Florida, the eastern coast of Canada, the Bahamas and the Caribbean region. The cargo shipping segment also includes amounts related to cargo insurance coverage sold to its customers and other third parties. The cargo shipping segment's vessels are under foreign registry, and its containers are considered instruments of international trade. Although the majority of its long-lived assets are foreign owned and its revenues are derived from foreign operations, the functional currency is generally the United States dollar. Our cargo shipping segment also includes an equity investment in Triton, a cargo container leasing business. Profits and losses are generally allocated to investor's capital accounts in proportion to their capital contributions. Our investment in Triton is accounted for under the equity method, and our share of earnings are reported within "Other Income" on our unaudited Condensed Consolidated Statements of Income.

Our other segment includes intercompany eliminations and aggregated subsidiaries that are not significant enough on a stand-alone basis and that do not fit into one of our other five operating segments.

We evaluate segment performance using the non-GAAP measure of EBIT that includes operating income, other income and expenses, and equity investment income. Items we do not include in EBIT are income taxes and financing costs, including interest and debt expense, each of which we evaluate on a consolidated basis. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income, earnings before income taxes and net income for the three months ended March 31, 2012 and, 2011 are presented below.

In millions	**2012**	**2011**
Operating income	$ 262	$ 238
Other income	4	1
EBIT	266	239
Interest expense	47	29
Earnings before income taxes	219	210
Income taxes	80	76
Net income	$ 139	$ 134

Information by segment on our Statements of Financial Position as of December 31, 2011, is as follows:

In millions	**Identifiable and total assets** (1)	**Goodwill**
Distribution operations	$ 11,020	$ 1,586
Retail operations	501	124
Wholesale services	1,214	2
Midstream operations	635	16
Cargo shipping	481	77
Other (2)	62	8
Consolidated	$ 13,913	$ 1,813

(1) Identifiable assets are those assets used in each segment’s operations.
(2) Our other segment’s assets consist primarily of cash and cash equivalents and PP&E and reflect the effect of intercompany eliminations.

Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the three months ended March 31, 2012 and 2011 are shown in the following tables. Note that our segments have changed as a result of our merger with Nicor and amounts from prior periods have been reclassified between the segments to reflect these changes.

2012

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 994	$ 263	$ 64	$ 16	$ 84	$ (17)	$ 1,404
Intercompany revenues (1)	46	0	0	0	0	(46)	0
Total operating revenues	1,040	263	64	16	84	(63)	1,404
Operating expenses							
Cost of goods sold	529	166	30	5	50	(61)	719
Operation and maintenance	173	32	13	5	28	(6)	245
Depreciation and amortization	88	4	1	2	6	3	104
Nicor merger expenses (2)	0	0	0	0	0	10	10
Taxes other than income taxes	57	1	1	1	2	2	64
Total operating expenses	847	203	45	13	86	(52)	1,142
Operating income (loss)	193	60	19	3	(2)	(11)	262
Other income	1	0	0	0	3	0	4
EBIT	$ 194	$ 60	$ 19	$ 3	$ 1	$ (11)	$ 266
Identifiable and total assets (3)	$ 10,785	$ 471	$ 917	$ 665	$ 477	$ (76)	$ 13,239
Goodwill	$ 1,586	$ 124	$ 2	$ 16	$ 77	$ 8	$ 1,813
Capital expenditures	$ 122	$ 2	$ 0	$ 42	$ 0	$ 5	$ 171

2011

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 505	$ 290	$ 53	$ 30	$ 0	$ 0	$ 878
Intercompany revenues (1)	38	0	0	0	0	(38)	0
Total operating revenues	543	290	53	30	0	(38)	878
Operating expenses							
Cost of goods sold	268	201	3	21	0	(38)	455
Operation and maintenance	90	20	16	4	0	(4)	126
Depreciation and amortization	36	1	0	2	0	2	41
Nicor merger expenses (2)	0	0	0	0	0	5	5
Taxes other than income taxes	9	0	1	1	0	2	13
Total operating expenses	403	222	20	28	0	(33)	640
Operating income (loss)	140	68	33	2	0	(5)	238
Other income	1	0	0	0	0	0	1
EBIT	$ 141	$ 68	$ 33	$ 2	$ 0	$ (5)	$ 239
Identifiable and total assets (3)	$ 5,481	$ 222	$ 981	$ 474	$ 0	$ (132)	$ 7,026
Goodwill	$ 404	$ 0	$ 0	$ 14	$ 0	$ 0	$ 418
Capital expenditures	$ 80	$ 1	$ 0	$ 7	$ 0	$ 6	$ 94

(1) Intercompany revenues – wholesale services records its energy marketing and risk management revenues on a net basis and its total operating revenues include intercompany revenues of $88 million for the three months ended March 31, 2012 and $147 million for the three months ended March 31, 2011.
(2) Transaction expenses associated with the Nicor merger are shown separately to better compare year-over-year results.
(3) Identifiable assets are those used in each segment's operations.
(4) Our other segment's assets consist primarily of cash and cash equivalents, PP&E and the effect of intercompany eliminations.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our unaudited Condensed Consolidated Financial Statements and the notes to the Condensed Consolidated Financial Statements in this quarterly filing, as well as our 2011 Form 10-K. Results for the interim periods presented are not necessarily indicative of the results to be expected for the full fiscal period due to seasonal and other factors.

Forward-Looking Statements

Certain expectations and projections regarding our future performance referenced in this section and elsewhere in this report, as well as in other reports and proxy statements we file with the SEC or otherwise release to the public and on our website are forward-looking statements within the meaning of the United States federal securities laws and are subject to uncertainties and risks. Senior officers and other employees may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

Forward-looking statements involve matters that are not historical facts, and because these statements involve anticipated events or conditions, forward-looking statements often include words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "proposed," "seek," "should," "target," "would," or similar expressions. You are cautioned not to place undue reliance on our forward-looking statements. Our expectations are not guarantees and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations are reasonable in view of currently available information, our expectations are subject to future events, risks and uncertainties, and there are numerous factors - many beyond our control - that could cause our actual results to vary significantly from our expectations.

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation including any changes related to climate change; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact on cost and timeliness of construction projects by government and other approvals, development project delays, adequacy of supply of diversified vendors, unexpected change in project costs, including the cost of funds to finance these projects; limits on pipeline capacity; the impact of acquisitions and divestitures; our ability to integrate successfully operations that we have or may acquire or develop in the future, including those of Nicor, and realize cost savings and any other synergies related to any such integration, or the risk that any such integration could be more difficult, time-consuming or costly than expected; uncertainty of our expected financial performance following the recent completion of the Nicor merger; disruption from the recent Nicor merger making it more difficult to maintain relationships with customers, employees or suppliers; direct or indirect effects on our business, financial condition or liquidity resulting from any change in our credit ratings resulting from the recent merger with Nicor or otherwise or any change in the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including disruptions in the capital markets and lending environment and the economic downturn; and general economic conditions; uncertainties about environmental issues and the related impact of such issues; the impact of changes in weather, including climate change, on the temperature-sensitive portions of our business; the impact of natural disasters such as hurricanes on the supply and price of natural gas; acts of war or terrorism; the outcome of litigation; and other factors discussed elsewhere herein and in our filings with the SEC.

We caution readers that the important factors described elsewhere in this report, among others, could cause our business, results of operations or financial condition to differ significantly from those expressed in any forward-looking statements. There also may be other factors that we cannot anticipate or that are not described in this report that could cause our actual results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of future events, new information or otherwise, except as required under United States federal securities law.

Overview

We are an energy services holding company whose principal business is the distribution of natural gas in seven states - Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland – through our seven natural gas distribution utilities. At March 31, 2012, our seven utilities served approximately 4.5 million end-use customers.

In addition to our primary business of the distribution of natural gas, we are involved in several related and complementary businesses. Our retail operations segment serves more than one million retail customers and markets natural gas and related home services to end-use customers in Georgia, Illinois, Ohio, Florida and New York. Our wholesale services segment provides natural gas storage arbitrage and related activities, natural gas asset management and related logistics activities for each of our utilities as well as for non-affiliated companies. Our midstream operations segment engages in the development and operation of high-deliverability natural gas storage assets and provides natural gas storage arbitrage and related activities. Our cargo shipping segment transports containerized freight, is an owner-lessor of cargo containers and provides cargo insurance.

Glossary of Key Terms

The operating revenues and EBIT of our distribution operations and retail operations segments are seasonal. During the Heating Season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. Our base operating expenses, excluding cost of gas, revenue taxes, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality.

Our retail operations businesses, including SouthStar, Nicor Advanced Energy and Nicor Solutions, generate earnings through the sale of natural gas to residential, commercial and industrial customers, primarily in Georgia and Illinois where we capture spreads between wholesale and retail natural gas prices. We also offer our customers energy-related products that provide for natural gas price stability and utility bill management. These products mitigate and/or eliminate the risks to customers of colder than normal weather and/or changes in natural gas prices. We charge a fee or premium for these services.

Our wholesale services segment consists of our wholly owned subsidiaries Sequent and Compass Energy (Compass). Sequent is involved in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing of natural gas across the United States and in Canada. Nicor Enerchange, which was integrated into Sequent as part of the Nicor merger, expands Sequent's wholesale marketing of natural gas supply services in the Midwest and enables Sequent to serve commercial and industrial customers in the Midwest primarily in the northern Illinois market. Further, Sequent manages Nicor Solutions' and Nicor Advanced Energy's product risks, including the purchase of natural gas supplies. Compass, which we acquired in 2007, provides natural gas supply and services to commercial, industrial and governmental customers primarily in Kentucky, Ohio, Pennsylvania, Virginia and West Virginia.

Our midstream operations segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability underground natural gas storage assets primarily in the Gulf Coast region of the United States and in northern California. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, the majority of our natural gas storage facilities are covered under a portfolio of short, medium and long-term contracts at a fixed market rate. Golden Triangle Storage's Cavern 1 began full commercial operations during the first quarter of 2011 and Cavern 2 is expected to be completed in mid-2012. Central Valley, located in northern California, is expected to begin full commercial operations in the first half of 2012.

Our cargo shipping segment, which joined our business as part of the Nicor merger, consists of Tropical Shipping, multiple wholly owned foreign subsidiaries of Tropical Shipping that are treated as disregarded entities for United States income tax purposes, Seven Seas, a wholly owned domestic cargo insurance company, and an equity investment in Triton, a cargo container leasing business. For additional information on our operating segments see Item 1, "Business" of our 2011 Form 10-K.

Executive Summary

Merger with Nicor On December 9, 2011, we closed the merger with Nicor. We are now the nation's largest natural gas-only distribution company based on customer count. In 2012 we will focus on the successful integration of the Nicor companies, including combining systems and personnel and utilizing best practices across businesses. In connection with the completion of our merger with Nicor, we reclassified some of our operating segments to be consistent with how management views and manages our business. See Note 10 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein for additional segment information including recasted prior period information.

For additional information on the Nicor merger see Note 3 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein and Item 1, "Business" as well as Note 3 to our Consolidated Financial Statements under Item 8 of our 2011 Form 10-K.

Legislative and regulatory update We continue to actively pursue a regulatory strategy that improves customer service and reduces the lag between our investments in infrastructure and the recovery of those investments through various rate mechanisms. If our rate design proposals are not approved, we will continue to work cooperatively with our regulators, legislators and others to create a framework that is conducive to our business goals and the interests of our customers and shareholders.

On December 20, 2011, the Virginia Commission approved an annual increase of $11 million in base rate revenues and established an authorized return on equity of 10% for Virginia Natural Gas with an overall return on rate base set at 7.38%. Additionally, $3.1 million of costs previously recovered through base rates will now be recovered through the company's gas cost recovery rate. Customer's bills will be credited to refund the difference between the final approved rates and interim rate increase, which began with usage on and after October 1, 2011. The new rate is expected to increase the average residential customer's monthly bill by less than $3.50 per month depending on usage.

Customer growth initiatives While there has been some improvement in the economic conditions within the areas we serve, we continue to see depressed housing markets with high inventories and significantly reduced new home construction. As a result, we have experienced only slight customer gains in the distribution operations and retail operations segments in the first quarter of 2012. Excluding Nicor Gas, our year-over-year consolidated utility customer growth rate was (0.2)% in the first quarter of 2012, compared to 0.2% for the first quarter of 2011. We anticipate overall competition and customer trends in 2012 to be similar to our 2011 results.

Impact of weather During the three months ended March 31, 2012, we experienced weather that was 18% - 40% warmer than normal accross our service territory. This resulted in a significantly reduced demand for natural gas, which negatively impacted our distribution operations, retail operations and wholesale services segments. The weather in Illinois was 19% warmer than normal. Georgia also experienced 32% warmer than normal weather, and 33% warmer than last year. This warmer weather reduced our expected operating margins by $13 million at distribution operations and by $8 million at retail operations as compared to normal weather.

Natural gas price volatility Natural gas market volatility arises from a number of factors such as weather fluctuations or changes in supply or demand for natural gas in different regions of the country. The volatility of natural gas commodity prices has a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of our wholesale services segment to capture value from location and seasonal spreads. During 2010, 2011 and 2012, the volatility of natural gas prices has been significantly lower than it had been for several prior years. This is the result of a robust natural gas supply, the weak economy, mild to much warmer than normal weather and ample natural gas storage. Our natural gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. Additionally, our hedging strategies and physical natural gas supplies in storage enable us to optimize within our wholesale and midstream businesses in a sustained low volatility market, but with lower actual results as compared to historical periods with higher volatility.

It is possible that natural gas prices will remain low for an extended period based on current levels of excess supply relative to market demand for natural gas, in part due to abundant sources of new shale natural gas reserves and the lack of demand by commercial and industrial enterprises. However, as economic conditions improve, the demand for natural gas may increase, natural gas prices could rise and higher volatility could return to the natural gas markets. Consequently, we are continuing to reposition our wholesales services business model through the management of operating costs, an increase in our fee-based services and continuing the optimization of our transportation and storage portfolio.

Hedges Changes in commodity prices subject a significant portion of our operations to earnings variability. Our non-utility businesses principally use physical and financial arrangements to reduce the risks associated with both weather-related seasonal fluctuations in market conditions and changing commodity prices. These economic hedges may not qualify, or are not designated for, hedge accounting treatment. As a result, our reported earnings for the wholesale services, retail operations and midstream operations segments reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating revenues or our OCI for those derivative instruments that qualify and are designated as accounting hedges.

Capital Projects We continue to focus on capital discipline and cost control, while moving ahead with projects and initiatives that we expect will have current and future benefits to us and our customers, provide an appropriate return on invested capital and ensure the safety, reliability and integrity of our utility infrastructure. The following table and discussions provide updates on some of our larger capital projects at our distribution operations segment. These programs update or expand our distribution systems to improve system reliability and meet operational flexibility and growth. Our anticipated expenditures for these programs in 2012 are discussed in 'Liquidity and Capital Resources' under the caption 'Cash Flows from Financing Activities' in our 2011 Form 10-K.

Dollars in millions	Utility	Expenditures in 2012	Expenditures since project inception	Miles of pipe replaced	Year project began	Anticipated year of completion
Pipeline replacement program	Atlanta Gas Light	$ 15	$ 582	2,554	1998	2013
Integrated System Reinforcement Program	Atlanta Gas Light	18	160	n/a	2009	2012
Integrated Customer Growth Program	Atlanta Gas Light	6	18	n/a	2010	2012
Enhanced infrastructure program	Elizabethtown Gas	3	92	88	2009	2012
Total		$ 42	$ 852	2,642		

Atlanta Gas Light Our STRIDE program is comprised of the ongoing pipeline replacement program, the Integrated System Reinforcement Program (i-SRP), and Integrated Customer Growth Program (i-CGP). The purpose of the i-SRP program under STRIDE is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Our i-CGP authorizes Atlanta Gas Light to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. Under STRIDE, we are required to file an updated ten-year forecast of infrastructure requirements under i-SRP along with a new construction plan every three years for review and approval by the Georgia Commission, which is required to be filed in August 2012.

Virginia Natural Gas In January 2012 Virginia Natural Gas filed an accelerated infrastructure replacement program with the Virginia Commission. The program was filed pursuant to a Virginia statute that provides a regulatory cost recovery mechanism to recover the costs associated with certain infrastructure replacement programs. Our proposed program is for a five-year period and includes a maximum allowance for capital expenditure of $25 million per year, not to exceed $105 million in total over the five-year period. A public hearing is scheduled for May 2012, and the Virginia Commission is expected to make a final decision on this proposed program in June 2012.

Elizabethtown Gas The New Jersey BPU-approved accelerated enhanced infrastructure program was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. On May 16, 2011, the New Jersey BPU approved Elizabethtown Gas' request to spend an additional $40 million under this program before the end of 2012. Costs associated with the investment in this program are recovered through periodic adjustments to base rates. We expect to file for an extension of the program.

Energy Marketing Activities Sequent's expected natural gas withdrawals from physical salt-dome and reservoir storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Sequent's expected operating revenues are net of the estimated impact of profit sharing under our asset management agreements and reflect the amounts that are realizable in future periods based on the inventory withdrawal schedule and forward natural gas prices at March 31, 2012 and 2011. A portion of Sequent's storage inventory is economically hedged with futures contracts, which results in realization of substantially fixed operating revenues, timing notwithstanding.

Withdrawal schedule	Withdrawal schedule (*in Bcf*) Total storage (in Bcf) (WACOG $2.30)	Expected operating revenues (*in millions)*
2012		
Second quarter	11	$ 2
Third quarter	11	3
Fourth quarter	7	4
2013	18	10
Total at March 31, 2012	47	$ 19
Total at March 31, 2011	12	$ 11

If Sequent's storage withdrawals associated with existing inventory positions are executed as planned, it expects operating revenues from storage withdrawals of approximately $19 million during the next twelve months. This will change as Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months and as forward NYMEX prices fluctuate. For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk of our 2011 Form 10-K."

Asset Management Agreements In March 2012, the Georgia Commission authorized the renewal of the asset management agreement between Atlanta Gas Light and Sequent. The renewed five-year agreement expires in March 2017 and requires Sequent to pay minimum annual fees of $3 million to the Georgia Universal service Fund and includes a slight increase in the sharing levels associated with storage inventory activity.

Results of Operations

We generate the majority of our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed, to residential, commercial and industrial customers from the date of the last bill to the end of the reporting period. No individual customer or industry accounts for a significant portion of our revenues.

We evaluate segment performance using the measures of operating margin and EBIT, which include the effects of corporate expense allocations. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of goods sold and revenue tax expense in distribution operations. Operating margin excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets. These items are included in our calculation of operating income as reflected in our unaudited Condensed Consolidated Statements of Income. EBIT is also a non-GAAP measure that includes operating income and other income and expenses. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated basis.

We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of goods sold and revenue tax expense can vary significantly and are generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail operations, wholesale services, midstream operations and cargo shipping segments since it is a direct measure of operating margin before overhead costs.

Glossary of Key Terms

We believe EBIT is a useful measurement of our operating segments' performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations. You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, our operating margin and EBIT measures may not be comparable to similarly titled measures of other companies. The following table reconciles operating revenue and operating margin to operating income and EBIT to earnings before income taxes and net income, together with other consolidated financial information for the periods presented.

	Three months ended March 31,		
In millions	2012	2011	Change
Operating revenues	$1,404	$ 878	$ 526
Cost of goods sold	(719)	(455)	(264)
Revenue tax expense (1)	(41)	0	(41)
Operating margin	644	423	221
Revenue tax expense (1)	41	0	41
Operating expenses (2)	(413)	(180)	(233)
Nicor merger expenses (3)	(10)	(5)	(5)
Operating income	262	238	24
Other income	4	1	3
EBIT	266	239	27
Interest expense, net	47	29	18
Earnings before income taxes	219	210	9
Income tax expense	80	76	4
Net income	139	134	5
Less net income attributable to the noncontrolling interest	9	10	(1)
Net income attributable to AGL Resources Inc.	$ 130	$ 124	$ 6

(1) Adjusted for revenue tax expenses for Nicor Gas, which are passed directly through to customers.
(2) Excludes transaction expenses associated with the merger with Nicor of approximately $10 million ($6 million net of tax) for the three months ended March 31, 2012 and $5 million ($3 million net of tax) for the three months ended March 31, 2011.
(3) Transaction expenses associated with the Nicor merger are part of operating expenses, but are shown separately to better compare year-over-year results.

For the first quarter of 2012, our net income attributable to AGL Resources Inc. increased by $6 million or 5% compared to last year. The increase was primarily the result of increased operating margins at distribution operations due to the merger with Nicor in December 2011 and increased regulatory infrastructure program revenues at Atlanta Gas Light. This increase was partially offset by lower EBIT at retail operations and wholesale services due to decreased average customer usage, warmer weather, and significantly lower natural gas volatility. Additionally, during the three months ended March 31, 2012, we recorded approximately $5 million ($3 million net of tax) of additional non-recurring transaction expenses associated with the merger with Nicor than we did during the same period last year. These costs are expensed as incurred.

Our interest expense increased by $18 million for the first quarter 2012 compared to the first quarter of 2011. This increase was primarily the result of higher average debt outstanding; primarily the result of the additional long term debt issued to fund the Nicor merger and the long term debt assumed in the transaction.

Our income tax expense increased by $4 million or 5% compared to the first quarter of 2011. The increase was primarily due to higher consolidated earnings as previously discussed. Our income tax expense is determined from earnings before income taxes less net income attributable to noncontrolling interest.

Selected weather, customer and volume metrics as of and for the three months ended March 31, 2012 and 2011, which we consider to be some of the key performance indicators for our operating segments, are presented in the following tables. We measure the effects of weather on our business through Heating Degree Days. Generally, increased Heating Degree Days result in greater demand for gas on our distribution systems. However, extended and unusually warmer than normal weather during the first quarter 2012 Heating Season had a significant negative impact on demand for natural gas in our distribution operations and retail operations segments.

Volume metrics for distribution operations and retail operations, as shown in the following table, present the effects of weather and our customers' demand for natural gas compared to prior year. Our customer metrics highlight the average number of customers to which we provide services. This number of customers can be impacted by natural gas prices, economic conditions and competition from alternative fuels.

Wholesale services' daily physical sales volumes represent the daily average natural gas volumes sold to its customers. Within our midstream operations segment, our natural gas storage businesses seek to have a significant percentage of their working natural gas capacity under firm subscription, but also take into account current and expected market conditions. This allows our natural gas storage business to generate additional revenue during times of peak market demand for natural gas storage services, but retain some consistency with their earnings and maximize the value of the investments. Our cargo shipping segment measures the volume of shipments during the period in TEUs, and we continue to seek opportunities to maximize the utilization of our containers and vessels.

Weather Heating Degree Days (1)

	Three months ended March 31, Normal	2012	2011	2012 vs. normal colder / (warmer)	2012 vs. 2011 colder / (warmer)
Illinois	2,902	2,358	3,199	(19)%	(26)%
Georgia	1,452	983	1,470	(32)%	(33)%
Virginia	1,800	1,275	1,908	(29)%	(33)%
New Jersey	2,515	1,984	2,549	(21)%	(22)%
Tennessee	1,654	1,205	1,673	(27)%	(28)%
Maryland	2,502	1,992	2,630	(20)%	(24)%
Florida	350	211	241	(40)%	(12)%
Ohio	2,575	2,119	2,616	(18)%	(19)%

Customers (average end-use customers - in thousands)	Three months ended March 31, 2012	2011	2012 vs. 2011 % change
Distribution Operations			
Nicor Gas	2,193	n/a	n/a%
Atlanta Gas Light	1,561	1,569	(0.5)
Virginia Natural Gas	282	280	0.7
Elizabethtown Gas	278	276	0.7
Florida City Gas	104	104	0.0
Chattanooga Gas	63	63	0.0
Elkton Gas	6	6	0.0
Total	4,487	2,298	n/a%
Retail Operations			
Georgia	494	498	(1)%
Illinois	445	n/a	n/a
Ohio and Florida (2)	122	71	72%
Indiana	47	n/a	n/a
Other	4	n/a	n/a
Total	1,112	569	n/a%
Market share in Georgia	32%	32%	0%

Volumes	Three months ended March 31, 2012	2011	2012 vs. 2011 % change
Distribution Operations In billion cubic feet (Bcf)			
Firm	240	101	n/a%
Interruptible	27	27	0%
Total	267	128	n/a%
Retail Operations (in Bcf)			
Georgia firm	14	18	(22)%
Ohio and Florida	4	4	0%
Wholesale Services			
Daily physical sales (Bcf/day)	6.0	5.8	3%
Cargo Shipping (TEU's – in thousands)			
Shipments	41	n/a	n/a

Midstream Operations	As of March 31, 2012	2011
Working natural gas capacity (in Bcf)	13.3	13.5
% of capacity under subscription by third parties (3)	68%	51%

(1) Obtained from weather stations relevant to our service areas at the National Oceanic and Atmospheric Administration, National Climatic Data Center. Normal represents ten-year averages from 2002 through March 31, 2012, except for Illinois, where normal represents a ten-year average from 1998 through 2007.
(2) A portion of the Ohio customers represents customer equivalents, which are computed by the actual delivered volumes divided by the expected average customer usage. On April 1, 2012, our contract to serve approximately 50,000 customer equivalents ended.
(3) Our percent of capacity under subscription does not include 4 Bcf of subscriptions with Sequent at March 31, 2012 and 2 Bcf at March 31, 2011. As of the end of March 2012, 3 Bcf of contracted capacity (2 Bcf related to Sequent) at Jefferson Island with an average rate of $0.213 expired and was fully recontracted effective April 1, 2012 (1 Bcf recontracted by Sequent) at an average rate of $0.084 with terms varying from 1 to 2 years.

First quarter 2012 compared to first quarter 2011

Operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables for the three months ended March 31, 2012 and 2011.

	2012			2011		
In millions	**Operating margin** (1) (2)	**Operating expenses** (2) (3)	**EBIT** (1)	**Operating margin** (1)	**Operating expenses** (3)	**EBIT** (1)
Distribution operations	$ 470	$ 277	$ 194	$ 275	$ 135	$ 141
Retail operations	97	37	60	89	21	68
Wholesale services	34	15	19	50	17	33
Midstream operations	11	8	3	9	7	2
Cargo shipping	34	36	1	0	0	0
Other	(2)	9	(11)	0	5	(5)
Consolidated	$ 644	$ 382	$ 266	$ 423	$ 185	$ 239

(1) These are non-GAAP measures. A reconciliation of operating margin to operating income and EBIT to earnings before income taxes and net income is contained in "Results of Operations" herein. Please note that our segments have changed as a result of our merger with Nicor and amounts presented from 2011 have been reclassified between the segments to reflect these changes. See Note 10 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein for additional segment information.
(2) Operating margin and expense for 2012 are adjusted for revenue tax expense for Nicor Gas which is passed directly through to customers.
(3) Includes $10 million in transaction expenses associated with the merger with Nicor during the first quarter of 2012 and $5 million for the same period in 2011.

Distribution Operations

Our distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the seven states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders.

With the exception of Atlanta Gas Light, our second largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers' ability to pay for gas consumed. With the exception of Nicor Gas, we have various mechanisms, such as weather normalization mechanisms, at all of our utilities, that limit our exposure to weather changes within typical ranges in all of our utilities' respective service areas. The expected operating margin contribution at our distribution operations segment was negatively impacted by warmer than normal weather by approximately $13 million in the first quarter. This primarily impacted Nicor Gas, whose operations are not reflected in our 2011 results. Distribution operations' EBIT increased by $53 million or 38% compared to last year as shown in the following table.

In millions		
EBIT – for first quarter of 2011		**$ 141**
Operating margin		
Increased margin from Nicor Gas as a result of the Nicor merger in December 2011	193	
Increased regulatory infrastructure program revenues at Atlanta Gas Light	2	
Increased revenues from new rates, customer growth and weather normalization at Virginia Natural Gas	1	
Decrease revenues from lower usage	(1)	
Increase in operating margin		**195**
Operating expenses		
Increased expenses for Nicor Gas as a result of the Nicor merger in December 2011	142	
Increased depreciation expense	3	
Increased pension and health benefits expenses	3	
Decreased payroll and incentive compensation expenses	(1)	
Decreased bad debt expense	(3)	
Decreased other expenses	(2)	
Increase in operating expenses		**142**
EBIT – for first quarter of 2012		**$ 194**

Retail Operations

Our retail operations segment, which consists of SouthStar and several businesses that provide energy-related products and services to retail markets, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to mitigate potential weather impacts. Retail operations' EBIT decreased by $8 million or 12% compared to last year as shown in the following table.

In millions		
EBIT – for first quarter of 2011		**$ 68**
Operating margin		
Increased margin as a result of the Nicor merger in December 2011	15	
Increased related to reduction of transportation and gas costs and higher retail price spreads	5	
Decreased average customer usage due to warmer than normal weather, net of weather derivatives	(8)	
Change in LOCOM adjustment	(3)	
Other	(1)	
Increase in operating margin		**8**
Operating expenses		
Increased expenses as a result of the Nicor merger in December 2011	16	
Increased outside services, legal and marketing expense	3	
Decreased payroll and benefits	(2)	
Decreased bad debt and other expenses	(1)	
Increase in operating expenses		**16**
EBIT – for first quarter of 2012		**$ 60**

Wholesale Services

Our wholesale services segment is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services and wholesale marketing. EBIT for our wholesale services segment is impacted by volatility in the natural gas market arising from a number of factors including weather fluctuations and changes in supply or demand for natural gas in different regions of the country. Wholesale services' EBIT decreased by $14 million compared to last year as shown in the following table. The decreases to operating margin are discussed in more detail below the table.

In millions		
EBIT – for first quarter of 2011		**$ 33**
Operating margin		
Change in value on storage hedges	19	
Change in value on transportation hedges	4	
Change in commercial activity driven by mild weather, lower storage and transportation price spreads	(21)	
Storage inventory write-down (LOCOM) in 2012	(18)	
Decrease in operating margin		**(16)**
Operating expenses		
Decreased incentive expenses, offset by slightly higher payroll, benefits, and depreciation	(2)	
Decrease in operating expenses		**(2)**
EBIT – for first quarter of 2012		**$ 19**

Change in Commercial activity The reduction in commercial activity reflects significantly lower natural gas price volatility impacting daily and intra-day storage and transportation spreads.

Change in storage and transportation hedges Seasonal (storage) and geographical location (transportation) spreads were higher as compared to prior year. However, overall natural gas price volatility remained low during 2012. Hedge gains in the first quarter of 2012 were primarily due to significantly larger seasonal and geographical location spreads at the time the hedges of our storage and transportation positions were executed and the subsequent downward movement of natural gas prices and collapse of regional transportation spreads.

The following table indicates the components of wholesale services' operating margin for the periods presented.

	March 31,	
In millions	2012	2011
Commercial activity recognized	$ 28	$ 49
Gain on transportation hedges	5	1
Gain on storage hedges	19	0
Inventory LOCOM	(18)	0
Operating margin	$ 34	$ 50

Midstream Operations

Our midstream operations segment's primary activity is our natural gas storage business, which develops, acquires and operates high-deliverability underground natural gas storage assets. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium to long-term contracts at a fixed market rate. Midstream operations' EBIT increased by $1 million compared to last year as shown in the following table.

In millions		
EBIT – for first quarter of 2011		**$2**
Operating margin		
Increased margin as a result of the Nicor merger in December 2011 driven by hedge gains, offset by inventory LOCOM adjustment at Central Valley	2	
Increase in operating margin		**2**
Operating expenses		
Increased property taxes, depreciation and other expenses	1	
Increase in operating expenses		**1**
EBIT – for first quarter of 2012		**$3**

Cargo Shipping

Our cargo shipping segment's primary activity is transporting containerized freight in the Bahamas and the Caribbean, a region that has historically been characterized by modest market growth and intense competition. Such shipments consist primarily of southbound cargo such as building materials, food and other necessities for developers, distributors and residents in the region, as well as tourist-related shipments intended for use in hotels and resorts, and on cruise ships. The balance of the cargo consists primarily of interisland shipments of consumer staples and northbound shipments of apparel, rum and agricultural products. Other related services such as inland transportation and cargo insurance are also provided within the cargo shipping segment. Our cargo shipping segment also includes an equity investment in Triton, a cargo container leasing business. For more information about our investment in Triton, see Note 10 to our Consolidated Financial Statements under Item 8 included in our 2011 Form 10-K. Cargo shipping reported $1 million of EBIT for the three months ending March 31, 2012.

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends, and working capital requirements are our most significant short-term financing requirements. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt. The liquidity required to fund our working capital, capital expenditures and other cash needs is primarily provided by our operating activities. Our short-term cash requirements not met by cash from operations are primarily satisfied with short-term borrowings under our commercial paper programs, which are supported by the AGL Credit Facility and the Nicor Gas Credit Facility. Periodically, we raise funds supporting our long-term cash needs from the issuance of long-term debt or equity securities. We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner.

Our capital market strategy has continued to focus on maintaining strong Consolidated Statements of Financial Position, ensuring ample cash resources and daily liquidity, accessing capital markets at favorable times as necessary, managing critical business risks and maintaining a balanced capital structure through the appropriate issuance of equity or long-term debt securities.

Our issuance of various securities, including long-term and short-term debt and equity, is subject to customary approval or review by state and federal regulatory bodies including the various commissions of the states in which we conduct business, the SEC and the FERC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow are derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. Nicor Gas is restricted by regulation in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. Dividends to AGL Resources are allowed only to the extent of Nicor Gas' retained earnings balance, which was $493 million at March 31, 2012.

We believe the amounts available to us under our senior notes, AGL Credit Facility and Nicor Gas Credit Facility, through the issuance of debt and equity securities, combined with cash provided by operating activities, will continue to allow us to meet our needs for working capital, pension contributions, construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments, common share repurchases and other cash needs through the next several years. Our ability to satisfy our working capital requirements and our debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which we are unable to control. These factors include, among others, regulatory changes, the price of and demand for natural gas and operational risks.

As of March 31, 2012, we had $74 million of cash and short and long-term investments on our unaudited Condensed Consolidated Statements of Financial Position that were generated from Tropical Shipping. This cash and the investments are not available for use by our other operations unless we repatriate a portion of Tropical Shipping's earnings in the form of a dividend that would be subject to a significant amount of United States income tax. See Note 12 to our Consolidated Financial Statements under Item 8 included in our 2011 Form 10-K for additional information on our income taxes.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. See Item 1A, "Risk Factors," in our 2011 Form 10-K for additional information on items that could impact our liquidity and capital resource requirements.

Credit Ratings Our borrowing costs and our ability to obtain adequate and cost effective financing are directly impacted by our credit ratings as well as the availability of financial markets. Credit ratings are important to our counterparties when we engage in certain transactions including over-the-counter derivatives. It is our long-term objective to maintain or improve our credit ratings in order to manage our existing financing costs and enhance our ability to raise additional capital on favorable terms.

Credit ratings and outlooks are opinions subject to ongoing review by the rating agencies and may periodically change. Each rating should be evaluated independently of other ratings. The rating agencies regularly review our performance, prospects and financial condition and reevaluate their ratings of our long-term debt and short-term borrowings, our corporate ratings and our ratings outlook. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. A credit rating is not a recommendation to buy, sell or hold securities.

Factors we consider important in assessing our credit ratings include our Consolidated Statements of Financial Position leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. The following table summarizes our credit ratings as of March 31, 2012, and reflects no change from December 31, 2011.

	AGL Resources			**Nicor Gas**		
	S&P	Moody's	Fitch	S&P	Moody's	Fitch
Corporate rating	BBB+	n/a	A-	BBB+	n/a	A
Commercial paper	A-2	P-2	F2	A-2	P-2	F-1
Senior unsecured	BBB+	Baa1	A-	BBB+	A3	A+
Senior secured	n/a	n/a	n/a	A	A1	AA-
Ratings outlook	Stable	Stable	Stable	Stable	Stable	Stable

Our credit ratings depend largely on our financial performance, and a downgrade in our current ratings, particularly below investment grade, would increase our borrowing costs and could limit our access to the commercial paper market. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

Default Provisions Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. Our credit facilities contain customary events of default, including, but not limited to, the failure to pay any interest or principal when due, the failure to furnish financial statements within the timeframe established by each debt facility, the failure to comply with certain affirmative and negative covenants, cross-defaults to certain other material indebtedness in excess of specified amounts, incorrect or misleading representations or warranties, insolvency or bankruptcy, fundamental change of control, the occurrence of certain Employee Retirement Income Security Act events, judgments in excess of specified amounts and certain impairments to the guarantee.

Our credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations, and other matters customarily restricted in such agreements.

Our credit facilities each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month. This ratio, as defined within our debt agreements, includes standby letters of credit, performance/surety bonds and the exclusion of other comprehensive income pension adjustments. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the periods presented.

	AGL Resources		Nicor Gas	
	March 31,		March 31,	
	2012	2011	2012	2011
Debt-to-capitalization ratio	54%	51%	47%	n/a

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, as of March 31, 2012 and 2011.

Our ratio of total debt to total capitalization, on a consolidated basis, is typically greater at the beginning of the Heating Season as we make additional short-term borrowings to fund our natural gas purchases and meet our working capital requirements. We intend to maintain our ratio of total debt to total capitalization in a target range of 50% to 60%. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings. For more information on our default provisions see Note 7 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein. The components of our capital structure, as calculated from our unaudited Condensed Consolidated Statements of Financial Position, as of the dates indicated, are provided in the following table.

	March 31, 2012	December 31, 2011	March 31, 2011
Short-term debt	10%	16%	1%
Long-term debt	46	43	53
Total debt	56	59	54
Equity	44	41	46
Total capitalization	100%	100%	100%

Cash Flows The following table provides a summary of our operating, investing and financing cash flows for the periods presented.

In millions	Three months ended March 31, 2012	2011	Variance
Net cash provided by (used in):			
Operating activities	$ 816	$ 718	$ 98
Investing activities	(171)	(94)	(77)
Financing activities	(643)	(563)	(80)
Net increase in cash and cash equivalents	2	61	(59)
Cash and cash equivalents at beginning of period	69	24	45
Cash and cash equivalents at end of period	$ 71	$ 85	$ (14)

Cash Flow from Operating Activities Our increase in cash from operations primarily related to the recovery of working capital from the companies acquired from Nicor in December 2011. This was offset by an increase in working capital requirements at wholesale services due to increased purchases of natural gas of $51 million and increased cash collateral requirements of $33 million as a result of changes in forward NYMEX curve prices in 2012.

Cash Flow from Investing Activities The increased PP&E expenditures of $77 million, or 82%, was primarily due to $35 million of PP&E expenditures at Nicor Gas and $39 million of PP&E expenditures at Central Valley. Both of these subsidiaries were acquired from our merger with Nicor in December 2011.

Cash Flow from Financing Activities The increased use of cash for our financing activities for the three months ended March 31, 2012 compared to the same period in 2011 was primarily a result of $200 million of long-term debt we issued in 2011 in anticipation of paying out the cash consideration for the Nicor merger. This was offset by reduced commercial paper payments.

As of March 31, 2012, our variable-rate debt was 26% of our total debt, compared to 36%, as of December 31, 2011 and 8% as of March 31, 2011. The decrease from December 31, 2011 was primarily due to decreased commercial paper borrowings. The increase from March 31, 2011 was primarily due to the proceeds from the $200 million long-term debt issuance used to repay commercial paper borrowings in 2011. As of March 31, 2012, our commercial paper borrowings of $730 million were 45% lower than as of December 31, 2011, primarily a result of lower working capital requirements. For more information on our debt, see Note 7 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein.

Short-term Debt Our short-term debt as of March 31, 2012 was comprised of borrowings under our commercial paper programs and current portions of our senior notes and capital leases.

In millions	**Period end balance outstanding** (1)	**Daily average balance outstanding** (2)	**Minimum balance outstanding** (2)	**Largest balance outstanding** (2)
Commercial paper - AGL Capital	$ 625	$ 752	$ 602	$ 922
Commercial paper - Nicor Gas	105	269	105	456
Senior notes	15	15	15	15
Capital leases	2	2	2	2
Total short-term debt and current portion of long-term debt and capital leases	$ 747	$ 1,038	$ 724	$ 1,395

(1) As of March 31, 2012.
(2) For the three months ended March 31, 2012. The minimum and largest balances outstanding for each short-term debt instrument occurred at different times during the year. As such, the total balances are not indicative of actual borrowings on any one day during the quarter.

The largest, minimum and daily average balances borrowed under our commercial paper programs are important when assessing the intra-period fluctuation of our short-term borrowings and potential liquidity risk. The fluctuations are due to our seasonal cash requirements.

Increasing natural gas commodity prices can have a significant impact on our commercial paper borrowings. Based on current natural gas prices and our expected injection plan, a $1 increase or decrease per thousand cubic feet of natural gas could result in a $170 million change of working capital requirements during the peak of the Heating Season. This range is sensitive to the timing of storage injections and withdrawals, collateral requirements and our portfolio position. Based on current natural gas prices and our expected purchases during the upcoming injection season, we believe that we have sufficient liquidity to cover our working capital needs for the upcoming Heating Season.

The lenders under our credit facilities and lines of credit are major financial institutions with $2.2 billion of committed balances and all have investment grade credit ratings as of March 31, 2012. It is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, we believe the risk of lender default is minimal.

Long-term Debt Our long-term debt matures more than one year from March 31, 2012, and consisted of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture during December 1989, senior notes, first mortgage bonds and gas facility revenue bonds.

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $14 million for the three months ended March 31, 2012 and $16 million for the same period in 2011.The primary reason for the reduction in the distribution to Piedmont during the current year is due to decreased earnings for 2011 compared to 2010.

Dividends on Common Stock Our common stock dividend payments were $42 million for the three months ended March 31, 2012 and $34 million for the same period in 2011. The increase is primarily due to the 38.2 million shares issued in conjunction with the Nicor merger and the annual dividend increase of $0.04 per share. However, as a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011, received a pro rata dividend of $0.0989 per share for the stub period, accruing from November 19, 2011 totaling $7 million. The dividend payments made in February 2012 were reduced by this stub period dividend.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of business that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor.

There were no significant changes to our contractual obligations described in Note 11 of our Consolidated Financial Statements and related notes as filed in Item 8 of our 2011 Form 10-K.

Pension and other retirement plan obligations In the first quarter of 2012, we contributed $17 million to our qualified pension plans and an additional $7 million in April 2012 for a total of $24 million during 2012. In 2011, we contributed $38 million to these qualified pension plans and an additional $6 million in April 2011 for a total of $44 million during 2011. Based on the current funding status of these plans, we would be required to make a minimum contribution to the plans of $15 million over the remainder of 2012. We may make additional contributions in 2012 in order to preserve the current level of benefits under these plans and in accordance with the funding requirements of the Pension Protection Act.

During the three months ended March 31, 2012, we recorded net periodic benefit costs of $10 million related to our defined benefit retirement plans compared to $5 million during the same period last year. We estimate that during the remainder of 2012, we will record net periodic benefit costs in the range of $44 million to $47 million, a $32 million to $35 million increase compared to 2011.

Substitute natural gas In 2011, Illinois enacted laws that required Nicor Gas and other large utilities in Illinois to elect to either sign contracts to purchase SNG from coal gasification plants to be constructed in Illinois or instead file rate cases with the Illinois Commission in 2012, 2014 and 2016.

On September 30, 2011, Nicor Gas signed an agreement to purchase approximately 25 Bcf of SNG annually for a 10-year term beginning as early as 2015. The counterparty intends to construct a 60 Bcf per year coal gasification plant in southern Illinois. The price of the SNG could significantly exceed market prices and is dependent upon a variety of factors. However, currently under the provisions of this contract the price could potentially be $9.95 per Mcf or more. The project is also expected to be financed by the counterparty with external debt and equity. This agreement complies with an Illinois statute that authorizes full recovery of the purchase costs; therefore we expect to recover such costs. Since the purchase agreement is contingent upon various milestones to be achieved by the counterparty to the agreement, our obligation is not certain at this time. The contract automatically terminates if construction does not commence by July 1, 2012. While the purchase agreement is a variable interest in the counterparty, we have concluded, based on a qualitative evaluation, that we are not the primary beneficiary required to consolidate the counterparty because we had no power to dictate the key terms of this agreement and we have no power to direct any of the activities of the seller. No amount has been recognized on our unaudited Condensed Consolidated Statements of Financial Position in connection with the purchase agreement.

Additionally, on October 11, 2011, the Illinois Power Agency (IPA) approved the form of a draft 30-year contract for the purchase by Nicor Gas of approximately 20 Bcf per year of SNG from a second proposed plant beginning as early as 2018. In November 2011, we filed a lawsuit against the IPA and the developer of this second proposed plant contending that the draft contract approved by the IPA does not conform to certain requirements of the enabling legislation. The lawsuit is pending in circuit court in DuPage County, Illinois. In accordance with the enabling legislation, the draft contract approved by the IPA for the second proposed plant was submitted to the Illinois Commission for further approvals by that regulatory body. The Illinois Commission issued an order on January 10, 2012 approving a final form of the contract for the second plant. The final form of contract approved by the Illinois Commission modified the draft contract submitted by the IPA in various respects. Both we and the developer of the plant filed applications for a rehearing with the Illinois Commission seeking changes to the final form of the contract. The Illinois Commission agreed to grant a rehearing on this contract and is expected to issue its ruling during the second quarter of 2012.

The purchase price of the SNG that may be produced from both of the coal gasification plants may significantly exceed market prices for natural gas and is dependent upon a variety of factors, including plant construction costs and volumes sold, and is currently unknown. The Illinois laws provide that prices paid for SNG purchased from the plants are to be considered prudent and not subject to review or disallowance by the Illinois Commission. As such, Illinois law effectively requires Nicor Gas' customers to provide subordinated financial support to the developers.

Critical Accounting Policies and Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts in our unaudited Condensed Consolidated Financial Statements and accompanying notes. Those judgments and estimates have a significant effect on our financial statements primarily due to the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ from those estimates. We frequently reevaluate our judgments and estimates that are based upon historical experience and various other assumptions that we believe to be reasonable under the circumstances.

Each of our critical accounting estimates involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. There have been no significant changes to our critical accounting estimates from those disclosed in our Management's Discussion and Analysis of Financial Condition and Results of Operation as filed on our 2011 Form 10-K. Our critical accounting estimates used in the preparation of our unaudited Condensed Consolidated Financial Statements include the following:

- Regulatory Infrastructure Program Liabilities
- Environmental Remediation Liabilities
- Derivatives and Hedging Activities
- Goodwill and Intangible Assets
- Contingencies
- Pension and Other Retirement Plans
- Income Taxes

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with natural gas prices, interest rates, credit and fuel prices. Natural gas price risk is defined as the potential loss that we may incur as a result of changes in the fair value of natural gas. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. Our fuel price risk is primarily in cargo shipping, which is partially reduced through fuel surcharges. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC), which prohibits the use of derivatives for speculative purposes.

Our RMC is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatment for our derivative instruments are described in further detail in Note 5 of our unaudited Condensed Consolidated Financial Statements.

Natural Gas Price Risk

The following tables include the fair values and average values of our consolidated derivative instruments as of the dates indicated. We base the average values on monthly averages for the three months ended March 31, 2012 and 2011.

	Derivative instruments average values (1) **at March 31,**	
In millions	**2012**	**2011**
Asset	$ 279	$ 197
Liability	117	47

(1) Excludes cash collateral amounts.

	Derivative instruments fair values netted with cash collateral at		
In millions	**Mar. 31, 2012**	**Dec. 31, 2011**	**Mar. 31, 2011**
Asset	$ 266	$ 288	$ 140
Liability	103	110	28

The following tables illustrate the change in the net fair value of our derivative instruments during the periods presented, and provide details of the net fair value of contracts outstanding as of the dates presented.

	Three months ended March 31,	
In millions	**2012**	**2011**
Net fair value of derivative instruments outstanding at beginning of period	$ 31	$ 55
Derivative instruments realized or otherwise settled during period	(82)	(48)
Change in net fair value of derivative instruments	5	17
Net fair value of derivative instruments outstanding at end of period	(46)	24
Netting of cash collateral	209	88
Cash collateral and net fair value of derivative instruments outstanding at end of period (1)	$ 163	$ 112

(1) Net fair value of derivative instruments outstanding includes premium and associated intrinsic value at March 31, 2011 of less than $1 million associated with weath

The sources of our net fair value at March 31, 2012, are as follows.

In millions	**Prices actively quoted (Level 1)** (1)	**Significant other observable inputs (Level 2)** (2)
Mature through 2012	$ (150)	$ 79
Mature 2013 – 2014	(26)	53
Mature 2015 – 2017	(4)	2
Total derivative instruments (3)	$ (180)	$ 134

(1) Valued using NYMEX futures prices.
(2) Valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are bas
(3) Excludes cash collateral amounts.

Value-at-risk Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally immaterial, permitting us to operate within relatively low VaR limits. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions. Our VaR is determined on a 95% confidence interval and a 1-day holding period. In simple terms, this means that 95% of the time, the risk of loss from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated.

We actively monitor open commodity positions and the resulting VaR. We also continue to maintain a relatively matched book, where our total buy volume is close to our sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, our portfolio positions for the three months ended March 31, 2012 and 2011 had the following VaRs.

	Three months ended March 31,	
In millions	**2012**	**2011**
Period end	$ 2.2	$ 1.8
Average	2.5	1.4
High	4.8	1.8
Low	1.9	0.9

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $1.1 billion of variable-rate debt outstanding at March 31, 2012, a 100 basis point change in market interest rates would have resulted in an increase in pretax interest expense of $11 million on an annualized basis.

We have $300 million of 6.4% senior notes due in July 2016. In May 2011, we entered into interest rate swaps related to these senior notes to effectively convert $250 million from a fixed rate to a variable-rate obligation. The interest rate resets quarterly based on LIBOR plus 3.9%.

On March 31, 2012, our forward-starting interest rate swaps totaling $90 million that were redesignated as cash flow hedges upon the close of the Nicor merger matured.

Interest rate swaps help us achieve our desired mix of variable to fixed rate debt (i.e. variable debt target of 20% to 45% of total debt). Any gain or loss on these interest rate swaps is deferred in accumulated other comprehensive income until settlement, at which point it is amortized to interest expense over the life of the related debt. For additional information, see Note 5 to our unaudited Condensed Consolidated Financial Statements under Item 1 herein.

Credit Risk

Wholesale Services We have established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. We also utilize master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the “net” mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. We also use other netting agreements with certain counterparties with whom we conduct significant transactions. Master netting agreements enable us to net certain assets and liabilities by counterparty. We also net across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions.

Additionally, we may require counterparties to pledge additional collateral when deemed necessary. We conduct credit evaluations and obtain appropriate internal approvals for our counterparty’s line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody’s and BBB- from S&P. Generally, we require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not have investment grade ratings.

We have a concentration of credit risk as measured by our 30-day receivable exposure plus forward exposure. As of March 31, 2012, our top 20 counterparties represented approximately 64% of the total counterparty exposure of $338 million, derived by adding together the top 20 counterparties’ exposures, exclusive of customer deposits, and dividing by the total of our counterparties’ exposures.

As of March 31, 2012, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of BBB+, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows our third-party natural gas contracts receivable and payable positions.

	Gross receivables			Gross payables		
In millions	**Mar. 31, 2012**	**Dec. 31, 2011**	**Mar. 31, 2011**	**Mar. 31, 2012**	**Dec. 31, 2011**	**Mar. 31, 2011**
Netting agreements in place:						
Counterparty is investment grade	$ 252	$ 395	$ 338	$ 192	$ 255	$ 258
Counterparty is non-investment grade	11	23	8	20	47	37
Counterparty has no external rating	121	184	208	212	288	317
No netting agreements in place:						
Counterparty is investment grade	2	4	9	1	0	14
Counterparty has no external rating	0	1	2	0	0	2
Amount recorded on unaudited Condensed Consolidated Statements of Financial Position	$ 386	$ 607	$ 565	$ 425	$ 590	$ 628

We have certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of its counterparties. If such collateral were not posted, our ability to continue transacting business with these counterparties would be impaired. If our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements with our counterparties would have totaled $20 million at March 31, 2012, which would not have a material impact to our consolidated results of operations, cash flows or financial condition.

There have been no other significant changes to our credit risk related to our other segments, as described in Item 7A "Quantitative and Qualitative Disclosures about Market Risk" of our 2011 Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

(a) ***Evaluation of disclosure controls and procedures***. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of March 31, 2012, the end of the period covered by this report. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of March 31, 2012, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) ***Changes in Internal Control over Financial Reporting.*** There were no changes in our internal control over financial reporting that occurred during the first quarter ended March 31, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition. For more information regarding some of these proceedings, see Note 9 to our unaudited Condensed Consolidated Financial Statements under the caption "Litigation."

Item 1A. Risk Factors

For information regarding our risk factors see the factors discussed in Part I, "Item 1A. Risk Factors" in our 2011 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in our 2011 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan. We purchased no shares for such purposes in the first quarter of 2012 and no unregistered sales of equity securities were made during this period.

Item 6. Exhibits

12	Statement of Computation of Ratio of Earnings to Fixed Charges.
31.1	Certification of John W. Somerhalder II pursuant to Rule 13a – 14(a).
31.2	Certification of Andrew W. Evans pursuant to Rule 13a – 14(a).
32.1	Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document. (1)
101.SCH	XBRL Taxonomy Extension Schema. (1)
101.CAL	XBRL Taxonomy Extension Calculation Linkbase. (1)
101.DEF	XBRL Taxonomy Definition Linkbase. (1)
101.LAB	XBRL Taxonomy Extension Labels Linkbase. (1)
101.PRE	XBRL Taxonomy Extension Presentation Linkbase. (1)

(1) Furnished, not filed

Attached as Exhibit 101 to this Quarterly Report are the following documents formatted in extensible business reporting language (XBRL): (i) Document and Entity Information; (ii) Condensed Consolidated Statements of Financial Position at March 31, 2012, December 31,2011 and March 31,2011; (iii) unaudited Condensed Consolidated Statements of Income for the three months ended March 31, 2012 and 2011; (iv) unaudited Condensed Consolidated Statements of Comprehensive Income for the three months ended March 31, 2012 and 2011; (v) unaudited Condensed Consolidated Statements of Equity for the three months ended March 31, 2012 and 2011; (vi) unaudited Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2012 and 2011; and (vii) Notes to unaudited Condensed Consolidated Financial Statements.

Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability. We also make available on our web site the Interactive Data Files submitted as Exhibit 101 to this Quarterly Report.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AGL RESOURCES INC.
(Registrant)

Date: May 1, 2012

/s/Andrew W. Evans
Executive Vice President and Chief Financial Officer

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AGL Resources Inc.
Statement Setting Forth Ratio of Earnings to Fixed Charges

Dollars in millions	Three months ended March 31, 2012	Fiscal 2011	Fiscal 2010	Fiscal 2009	Fiscal 2008	Fiscal 2007
Earnings before income taxes	$ 219	$ 311	$ 390	$ 384	$ 369	$ 369
Add:						
Fixed charges (see "B" below)	52	145	123	115	127	127
Amortization of capitalized interest	-	1	-	-	-	-
Distributed income of equity investees	3	-	-	-	-	-
Less:						
Interest capitalized	-	(1)	(5)	(3)	(2)	(2)
Noncontrolling interest in pre-tax income of subsidiaries that have not incurred fixed charges	(9)	(14)	(16)	(27)	(20)	(20)
Adjusted Earnings (A)	$ 265	$ 442	$ 492	$ 469	$ 474	$ 474
Fixed charges						
Interest on long-term debt	$ 45	$ 101	$ 109	$ 98	$ 96	$ 96
Other interest, including amortized premiums, discounts and capitalized expenses related to indebtedness liability	4	37	7	10	24	24
Estimated interest components of rentals	3	7	7	7	7	7
Total fixed charges (B)	$ 52	$ 145	$ 123	$ 115	$ 127	$ 127
Ratio of earnings to fixed charges (A)/(B)	5.10	3.05	4.00	4.08	3.73	3.73

Exhibit 31.1 – Certification of John W. Somerhalder II pursuant to Rule 13a – 14(a)

CERTIFICATIONS

I, John W. Somerhalder II, certify that:

1. I have reviewed this quarterly report on Form 10-Q of AGL Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2012

/s/ John W. Somerhalder II
Chairman, President and Chief Executive Officer

Exhibit 31.2 – Certification of Andrew W. Evans pursuant to Rule 13a – 14(a)

CERTIFICATIONS

I, Andrew W. Evans, certify that:

1. I have reviewed this quarterly report on Form 10-Q of AGL Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2012

/s/ Andrew W. Evans
Executive Vice President and Chief Financial Officer

Exhibit 32.1 **Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350**

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

The undersigned, as the chief executive officer of AGL Resources Inc., certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) the Form 10-Q for the quarterly period ended March 31, 2012 (the "Report"), which accompanies this certification, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of AGL Resources Inc.

Date: May 1, 2012

/s/ John W. Somerhalder II
Chairman, President and Chief Executive Officer

Exhibit 32.2 **Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350**

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

The undersigned, as the chief financial officer of AGL Resources Inc., certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) the Form 10-Q for the quarterly period ended March 31, 2012 (the "Report"), which accompanies this certification, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of AGL Resources Inc.

Date: May 1, 2012

/s/ Andrew W. Evans
Executive Vice President and Chief Financial Officer

INTERSTATE POWER & LIGHT CO (IPL PR B)

10-Q

Quarterly report pursuant to sections 13 or 15(d)
Filed on 05/04/2012
Filed Period 03/31/2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2012

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number	Name of Registrant, State of Incorporation, Address of Principal Executive Offices and Telephone Number	IRS Employer Identification Number
1-9894	ALLIANT ENERGY CORPORATION (a Wisconsin corporation) 4902 N. Biltmore Lane Madison, Wisconsin 53718 Telephone (608)458-3311	39-1380265
0-4117-1	INTERSTATE POWER AND LIGHT COMPANY (an Iowa corporation) Alliant Energy Tower Cedar Rapids, Iowa 52401 Telephone (319)786-4411	42-0331370
0-337	WISCONSIN POWER AND LIGHT COMPANY (a Wisconsin corporation) 4902 N. Biltmore Lane Madison, Wisconsin 53718 Telephone (608)458-3311	39-0714890

This combined Form 10-Q is separately filed by Alliant Energy Corporation, Interstate Power and Light Company and Wisconsin Power and Light Company. Information contained in the Form 10-Q relating to Interstate Power and Light Company and Wisconsin Power and Light Company is filed by such registrant on its own behalf. Each of Interstate Power and Light Company and Wisconsin Power and Light Company makes no representation as to information relating to registrants other than itself.

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company Filer
Alliant Energy Corporation	☒			
Interstate Power and Light Company			☒	
Wisconsin Power and Light Company			☒	

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Number of shares outstanding of each class of common stock as of March 31, 2012:

Alliant Energy Corporation	Common stock, $0.01 par value, 110,962,089 shares outstanding
Interstate Power and Light Company	Common stock, $2.50 par value, 13,370,788 shares outstanding (all of which are owned beneficially and of record by Alliant Energy Corporation)

Wisconsin Power and Light Company	Common stock, $5 par value, 13,236,601 shares outstanding (all of which are owned beneficially and of record by Alliant Energy Corporation)

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FORWARD-LOOKING STATEMENTS

Statements contained in this report that are not of historical fact are forward-looking statements intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995. These forward-looking statements can be identified as such because the statements include words such as "expect," "anticipate," "plan" or other words of similar import. Similarly, statements that describe future financial performance or plans or strategies are forward-looking statements. Such forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. Some, but not all, of the risks and uncertainties of Alliant Energy Corporation (Alliant Energy), Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL) that could materially affect actual results include:

- federal and state regulatory or governmental actions, including the impact of energy, tax, financial and health care legislation, and of regulatory agency orders;
- IPL's and WPL's ability to obtain adequate and timely rate relief to allow for, among other things, the recovery of operating costs, fuel costs, transmission costs, deferred expenditures, capital expenditures, and remaining costs related to generating units that may be permanently closed, earning their authorized rates of return, and the payments to their parent of expected levels of dividends;
- weather effects on results of utility operations;
- the ability to continue cost controls and operational efficiencies;
- the impact of IPL's retail electric base rate freeze in Iowa through 2013;
- the impact of WPL's potential retail electric and gas rate freeze in Wisconsin through 2014;
- the state of the economy in IPL's and WPL's service territories and resulting implications on sales, margins and ability to collect unpaid bills;
- developments that adversely impact Alliant Energy's, IPL's and WPL's ability to implement their strategic plans, including unanticipated issues with new emission control equipment for various coal-fired generating facilities of IPL and WPL, WPL's purchase of the Riverside Energy Center (Riverside), IPL's potential construction of a new natural gas-fired electric generating facility in Iowa, Alliant Energy Resources, LLC's (Resources') construction of and selling price of the electricity output from its new 100 megawatt (MW) wind project, and the potential decommissioning of certain generating facilities of IPL and WPL;
- the impact of changes to government incentive elections for wind projects;
- successful resolution of the pending challenge by interveners of the approval by the Public Service Commission of Wisconsin (PSCW) of WPL's Bent Tree—Phase I wind project;
- issues related to the availability of generating facilities and the supply and delivery of fuel and purchased electricity and the price thereof, including the ability to recover and to retain the recovery of purchased power, fuel and fuel-related costs through rates in a timely manner;
- the impact that fuel and fuel-related prices may have on IPL's and WPL's customers' demand for utility services;
- the ability to defend against environmental claims brought by state and federal agencies, such as the United States of America (U.S.) Environmental Protection Agency (EPA), or third parties, such as the Sierra Club;
- issues associated with environmental remediation efforts and with environmental compliance generally, including changing environmental laws and regulations and litigations associated with changing environmental laws and regulations;
- the ability to recover through rates all environmental compliance and remediation costs, including costs for projects put on hold due to uncertainty of future environmental laws and regulations;
- impacts of future tax benefits from deductions for repairs expenditures and mixed service costs and temporary differences from historical tax benefits from such deductions that are reversing into income tax expense in future periods;
- the ability to find a purchaser for RMT, Inc. (RMT), to successfully negotiate a purchase agreement and to close the sale of RMT;

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- continued access to the capital markets on competitive terms and rates, and the actions of credit rating agencies;
- inflation and interest rates;
- changes to the creditworthiness of counterparties with which Alliant Energy, IPL and WPL have contractual arrangements, including participants in the energy markets and fuel suppliers and transporters;
- issues related to electric transmission, including operating in Regional Transmission Organization (RTO) energy and ancillary services markets, the impacts of potential future billing adjustments and cost allocation changes from RTOs and recovery of costs incurred;
- unplanned outages, transmission constraints or operational issues impacting fossil or renewable generating facilities and risks related to recovery of resulting incremental costs through rates;
- Alliant Energy's ability to successfully pursue appropriate appeals with respect to, and any liabilities arising out of, the alleged violation of the Employee Retirement Income Security Act of 1974 (ERISA) by Alliant Energy's Cash Balance Pension Plan (Cash Balance Plan);
- current or future litigation, regulatory investigations, proceedings or inquiries;
- Alliant Energy's ability to sustain its dividend payout ratio goal;
- employee workforce factors, including changes in key executives, collective bargaining agreements and negotiations, work stoppages or additional restructurings;
- impacts that storms or natural disasters in IPL's and WPL's service territories may have on their operations and recovery of, and rate relief for, costs associated with restoration activities;
- access to technological developments;
- any material post-closing adjustments related to any past asset divestitures;
- material changes in retirement and benefit plan costs;
- the impact of incentive compensation plans accruals;
- the effect of accounting pronouncements issued periodically by standard-setting bodies;
- the impact of adjustments made to deferred tax assets and liabilities from state apportionment assumptions;
- the ability to utilize tax credits and net operating losses generated to date, and those that may be generated in the future, before they expire;
- the ability to successfully complete tax audits and appeals with no material impact on earnings and cash flows;
- the direct or indirect effects resulting from terrorist incidents, including cyber terrorism, or responses to such incidents; and
- factors listed in Management's Discussion and Analysis of Financial Condition and Results of Operations and in Item 1A Risk Factors in the combined Annual Report on Form 10-K filed by Alliant Energy, IPL and WPL for the year ended Dec. 31, 2011 (2011 Form 10-K).

Alliant Energy, IPL and WPL assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

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PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

ALLIANT ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(dollars in millions, except per share amounts)	
Operating revenues:		
Utility:		
Electric	**$ 572.4**	$ 620.3
Gas	**167.1**	229.0
Other	**13.7**	16.7
Non-regulated	**12.5**	11.2
Total operating revenues	**765.7**	877.2
Operating expenses:		
Utility:		
Electric production fuel and energy purchases	**159.9**	194.0
Purchased electric capacity	**61.5**	57.8
Electric transmission service	**81.4**	73.6
Cost of gas sold	**104.8**	156.4
Other operation and maintenance	**150.0**	160.6
Non-regulated operation and maintenance	**4.2**	4.6
Depreciation and amortization	**83.0**	77.8
Taxes other than income taxes	**25.3**	25.1
Total operating expenses	**670.1**	749.9
Operating income	**95.6**	127.3
Interest expense and other:		
Interest expense	**38.9**	40.5
Equity income from unconsolidated investments, net	**(9.4)**	(9.9)
Allowance for funds used during construction	**(3.8)**	(3.1)
Interest income and other	**(1.1)**	(0.8)
Total interest expense and other	**24.6**	26.7
Income from continuing operations before income taxes	**71.0**	100.6
Income taxes	**27.7**	22.4
Income from continuing operations, net of tax	**43.3**	78.2
Income (loss) from discontinued operations, net of tax	**(4.4)**	1.5
Net income	**38.9**	79.7
Preferred dividend requirements of subsidiaries	**4.0**	6.2
Net income attributable to Alliant Energy common shareowners	**$ 34.9**	$ 73.5
Weighted average number of common shares outstanding (basic) (000s)	**110,716**	110,569
Weighted average number of common shares outstanding (diluted) (000s)	**110,741**	110,632
Earnings per weighted average common share attributable to Alliant Energy common shareowners (basic and diluted):		
Income from continuing operations, net of tax	**$ 0.36**	$ 0.65
Income (loss) from discontinued operations, net of tax	**(0.04)**	0.01
Net income	**$ 0.32**	$ 0.66
Amounts attributable to Alliant Energy common shareowners:		
Income from continuing operations, net of tax	**$ 39.3**	$ 72.0
Income (loss) from discontinued operations, net of tax	**(4.4)**	1.5
Net income attributable to Alliant Energy common shareowners	**$ 34.9**	$ 73.5
Dividends declared per common share	**$ 0.45**	$ 0.425

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

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ALLIANT ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2012	December 31, 2011
	(in millions)	
ASSETS		
Property, plant and equipment:		
Utility:		
Electric plant in service	**$ 8,212.9**	$ 8,165.4
Gas plant in service	**855.2**	852.9
Other plant in service	**514.4**	510.1
Accumulated depreciation	**(3,252.3)**	(3,206.0)
Net plant	**6,330.2**	6,322.4
Construction work in progress:		
Edgewater Generating Station Unit 5 emission controls (Wisconsin Power and Light Company)	**89.0**	77.7
Other	**205.8**	179.5
Other, less accumulated depreciation	**34.7**	34.9
Total utility	**6,659.7**	6,614.5
Non-regulated and other:		
Non-regulated Generation, less accumulated depreciation	**276.0**	270.6
Alliant Energy Corporate Services, Inc. and other, less accumulated depreciation	**145.6**	148.2
Total non-regulated and other	**421.6**	418.8
Total property, plant and equipment	**7,081.3**	7,033.3
Current assets:		
Cash and cash equivalents	**30.9**	11.4
Accounts receivable:		
Customer, less allowance for doubtful accounts	**92.2**	88.1
Unbilled utility revenues	**62.2**	75.1
Other, less allowance for doubtful accounts	**92.7**	114.9
Income tax refunds receivable	**34.9**	39.1
Production fuel, at weighted average cost	**111.0**	101.9
Materials and supplies, at weighted average cost	**61.7**	58.5
Gas stored underground, at weighted average cost	**27.4**	57.7
Regulatory assets	**109.0**	103.6
Prepaid gross receipts tax	**31.4**	40.2
Assets held for sale	**66.8**	119.6
Prepayments and other	**60.4**	60.5
Total current assets	**780.6**	870.6
Investments:		
Investment in American Transmission Company LLC	**242.3**	238.8
Other	**61.4**	61.9
Total investments	**303.7**	300.7
Other assets:		
Regulatory assets	**1,380.4**	1,391.4
Deferred charges and other	**82.2**	91.9
Total other assets	**1,462.6**	1,483.3
Total assets	**$ 9,628.2**	$ 9,687.9

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

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ALLIANT ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) (Continued)

	March 31, 2012	December 31, 2011
	(in millions, except per share and share amounts)	
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Alliant Energy Corporation common equity:		
Common stock—$0.01 par value—240,000,000 shares authorized; 110,962,089 and 111,018,821 shares outstanding	**$ 1.1**	$ 1.1
Additional paid-in capital	**1,510.0**	1,510.8
Retained earnings	**1,495.2**	1,510.2
Accumulated other comprehensive loss	**(0.8)**	(0.8)
Shares in deferred compensation trust—249,298 and 262,735 shares at a weighted average cost of $32.10 and $31.68 per share	**(8.0)**	(8.3)
Total Alliant Energy Corporation common equity	**2,997.5**	3,013.0
Cumulative preferred stock of Interstate Power and Light Company	**145.1**	145.1
Noncontrolling interest	**1.8**	1.8
Total equity	**3,144.4**	3,159.9
Cumulative preferred stock of Wisconsin Power and Light Company	**60.0**	60.0
Long-term debt, net (excluding current portion)	**2,728.2**	2,703.1
Total capitalization	**5,932.6**	5,923.0
Current liabilities:		
Current maturities of long-term debt	**1.4**	1.4
Commercial paper	**57.0**	102.8
Accounts payable	**263.9**	267.8
Regulatory liabilities	**156.4**	164.7
Accrued taxes	**39.7**	46.9
Accrued interest	**46.6**	46.6
Derivative liabilities	**61.9**	55.9
Liabilities held for sale	**59.1**	62.1
Other	**87.3**	107.0
Total current liabilities	**773.3**	855.2
Other long-term liabilities and deferred credits:		
Deferred income taxes	**1,637.7**	1,592.2
Regulatory liabilities	**726.1**	745.4
Pension and other benefit obligations	**309.6**	312.7
Other	**248.9**	259.4
Total long-term liabilities and deferred credits	**2,922.3**	2,909.7
Total capitalization and liabilities	**$ 9,628.2**	$ 9,687.9

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

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ALLIANT ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Cash flows from operating activities:		
Net income	**$ 38.9**	$ 79.7
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	**83.6**	78.8
Other amortizations	**14.0**	13.8
Deferred tax expense (benefit) and investment tax credits	**31.9**	(4.1)
Equity income from unconsolidated investments, net	**(9.4)**	(9.9)
Distributions from equity method investments	**8.6**	8.3
Other	**(1.8)**	1.3
Other changes in assets and liabilities:		
Accounts receivable	**63.9**	(0.4)
Sales of accounts receivable	**5.0**	10.0
Production fuel	**(9.1)**	32.6
Gas stored underground	**30.3**	34.4
Regulatory assets	**(18.9)**	(137.1)
Regulatory liabilities	**(26.5)**	159.2
Derivative liabilities	**5.2**	(25.9)
Deferred income taxes	**13.2**	45.0
Other	**(13.9)**	(24.4)
Net cash flows from operating activities	**215.0**	261.3
Cash flows used for investing activities:		
Construction and acquisition expenditures:		
Utility business	**(122.1)**	(229.4)
Alliant Energy Corporate Services, Inc. and non-regulated businesses	**(13.5)**	(7.7)
Other	**0.5**	3.8
Net cash flows used for investing activities	**(135.1)**	(233.3)
Cash flows used for financing activities:		
Common stock dividends	**(49.9)**	(47.1)
Preferred dividends paid by subsidiaries	**(4.0)**	(4.7)
Net change in commercial paper	**(20.8)**	(15.0)
Other	**14.3**	5.6
Net cash flows used for financing activities	**(60.4)**	(61.2)
Net increase (decrease) in cash and cash equivalents	**19.5**	(33.2)
Cash and cash equivalents at beginning of period	**11.4**	159.3
Cash and cash equivalents at end of period	**$ 30.9**	$ 126.1
Supplemental cash flows information:		
Cash paid (refunded) during the period for:		
Interest, net of capitalized interest	**$ 38.8**	$ 40.2
Income taxes, net of refunds	**$ (0.1)**	$ (3.0)
Significant noncash investing and financing activities:		
Accrued capital expenditures	**$ 42.0**	$ 28.6

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

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INTERSTATE POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Operating revenues:		
Electric utility	**$ 293.1**	$ 330.2
Gas utility	**92.8**	131.9
Steam and other	**12.8**	15.4
Total operating revenues	**398.7**	477.5
Operating expenses:		
Electric production fuel and energy purchases	**74.1**	96.8
Purchased electric capacity	**41.0**	39.3
Electric transmission service	**55.5**	47.9
Cost of gas sold	**57.3**	92.6
Other operation and maintenance	**86.9**	96.7
Depreciation and amortization	**46.7**	43.9
Taxes other than income taxes	**13.3**	13.2
Total operating expenses	**374.8**	430.4
Operating income	**23.9**	47.1
Interest expense and other:		
Interest expense	**19.7**	19.9
Allowance for funds used during construction	**(1.5)**	(1.4)
Interest income and other	**(0.2)**	(0.2)
Total interest expense and other	**18.0**	18.3
Income before income taxes	**5.9**	28.8
Income taxes	**7.4**	1.7
Net income (loss)	**(1.5)**	27.1
Preferred dividend requirements	**3.2**	5.4
Earnings available (loss) for common stock	**$ (4.7)**	$ 21.7

Earnings per share data is not disclosed given Alliant Energy Corporation is the sole shareowner of all shares of IPL's common stock outstanding during the periods presented.

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

INTERSTATE POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2012	December 31, 2011
	(in millions)	
ASSETS		
Property, plant and equipment:		
Electric plant in service	$ 4,703.8	$ 4,684.0
Gas plant in service	429.4	428.2
Steam plant in service	35.0	34.9
Other plant in service	251.5	246.4
Accumulated depreciation	(1,854.9)	(1,833.8)
Net plant	3,564.8	3,559.7
Construction work in progress	107.7	96.6
Other, less accumulated depreciation	19.9	19.8
Total property, plant and equipment	3,692.4	3,676.1
Current assets:		
Cash and cash equivalents	23.1	2.1
Accounts receivable, less allowance for doubtful accounts	51.9	75.2
Income tax refunds receivable	14.6	28.4
Production fuel, at weighted average cost	69.3	67.7
Materials and supplies, at weighted average cost	32.8	31.5
Gas stored underground, at weighted average cost	6.8	25.5
Regulatory assets	63.9	59.0
Prepayments and other	26.6	33.7
Total current assets	289.0	323.1
Investments	17.1	16.8
Other assets:		
Regulatory assets	1,049.0	1,058.3
Deferred charges and other	19.1	19.2
Total other assets	1,068.1	1,077.5
Total assets	$ 5,066.6	$ 5,093.5

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

INTERSTATE POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) (Continued)

	March 31, 2012	December 31, 2011
	(in millions, except per share and share amounts)	
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Interstate Power and Light Company common equity:		
Common stock—$2.50 par value—24,000,000 shares authorized; 13,370,788 shares outstanding	**$ 33.4**	$ 33.4
Additional paid-in capital	**927.7**	927.7
Retained earnings	**398.9**	433.3
Total Interstate Power and Light Company common equity	**1,360.0**	1,394.4
Cumulative preferred stock	**145.1**	145.1
Total equity	**1,505.1**	1,539.5
Long-term debt, net	**1,334.1**	1,309.0
Total capitalization	**2,839.2**	2,848.5
Current liabilities:		
Commercial paper	**—**	7.1
Accounts payable	**136.7**	118.2
Accounts payable to associated companies	**27.3**	36.7
Regulatory liabilities	**117.8**	137.1
Accrued taxes	**48.3**	43.8
Accrued interest	**23.0**	22.8
Derivative liabilities	**30.1**	24.5
Other	**31.0**	32.3
Total current liabilities	**414.2**	422.5
Other long-term liabilities and deferred credits:		
Deferred income taxes	**954.7**	936.9
Regulatory liabilities	**569.3**	584.2
Pension and other benefit obligations	**100.8**	101.9
Other	**188.4**	199.5
Total other long-term liabilities and deferred credits	**1,813.2**	1,822.5
Total capitalization and liabilities	**$ 5,066.6**	$ 5,093.5

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

INTERSTATE POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Cash flows from operating activities:		
Net income (loss)	**$ (1.5)**	$ 27.1
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Depreciation and amortization	**46.7**	43.9
Deferred tax expense (benefit) and investment tax credits	**7.0**	(37.3)
Other	**1.3**	2.0
Other changes in assets and liabilities:		
Accounts receivable	**18.3**	10.4
Sales of accounts receivable	**5.0**	10.0
Income tax refunds receivable	**13.8**	(8.7)
Production fuel	**(1.6)**	20.4
Gas stored underground	**18.7**	18.0
Regulatory assets	**(9.0)**	(145.0)
Regulatory liabilities	**(33.6)**	159.0
Accrued taxes	**4.5**	(28.4)
Derivative liabilities	**4.5**	(12.7)
Deferred income taxes	**10.6**	49.5
Other	**(6.6)**	20.1
Net cash flows from operating activities	**78.1**	128.3
Cash flows used for investing activities:		
Utility construction and acquisition expenditures	**(56.6)**	(104.6)
Other	**(4.8)**	(5.2)
Net cash flows used for investing activities	**(61.4)**	(109.8)
Cash flows from (used for) financing activities:		
Common stock dividends	**(29.7)**	—
Preferred stock dividends	**(3.2)**	(3.9)
Repayment of capital to parent	**—**	(29.8)
Net change in commercial paper	**17.9**	—
Changes in cash overdrafts	**19.3**	13.3
Other	**—**	0.1
Net cash flows from (used for) financing activities	**4.3**	(20.3)
Net increase (decrease) in cash and cash equivalents	**21.0**	(1.8)
Cash and cash equivalents at beginning of period	**2.1**	5.7
Cash and cash equivalents at end of period	**$ 23.1**	$ 3.9
Supplemental cash flows information:		
Cash paid (refunded) during the period for:		
Interest	**$ 19.4**	$ 19.3
Income taxes, net of refunds	**($ 14.4)**	$ 22.0
Significant noncash investing and financing activities:		
Accrued capital expenditures	**$ 23.5**	$ 16.6

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

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WISCONSIN POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Operating revenues:		
Electric utility	$ 279.3	$ 290.1
Gas utility	74.3	97.1
Other	0.9	1.3
Total operating revenues	354.5	388.5
Operating expenses:		
Electric production fuel and energy purchases	85.8	97.2
Purchased electric capacity	20.5	18.5
Electric transmission service	25.9	25.7
Cost of gas sold	47.5	63.8
Other operation and maintenance	63.1	63.9
Depreciation and amortization	35.8	33.4
Taxes other than income taxes	11.3	11.2
Total operating expenses	289.9	313.7
Operating income	64.6	74.8
Interest expense and other:		
Interest expense	20.0	20.1
Equity income from unconsolidated investments	(10.1)	(9.4)
Allowance for funds used during construction	(2.3)	(1.7)
Interest income and other	(0.1)	—
Total interest expense and other	7.5	9.0
Income before income taxes	57.1	65.8
Income taxes	25.2	21.4
Net income	31.9	44.4
Preferred dividend requirements	0.8	0.8
Earnings available for common stock	$ 31.1	$ 43.6

Earnings per share data is not disclosed given Alliant Energy Corporation is the sole shareowner of all shares of WPL's common stock outstanding during the periods presented.

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

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WISCONSIN POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2012	December 31, 2011
	(in millions)	
ASSETS		
Property, plant and equipment:		
Electric plant in service	**$ 3,509.1**	$ 3,481.4
Gas plant in service	**425.8**	424.7
Other plant in service	**227.9**	228.8
Accumulated depreciation	**(1,397.4)**	(1,372.2)
Net plant	**2,765.4**	2,762.7
Leased Sheboygan Falls Energy Facility, less accumulated amortization	**81.7**	83.2
Construction work in progress:		
Edgewater Generating Station Unit 5 emission controls	**89.0**	77.7
Other	**98.1**	82.9
Other, less accumulated depreciation	**14.8**	15.1
Total property, plant and equipment	**3,049.0**	3,021.6
Current assets:		
Cash and cash equivalents	**2.1**	2.7
Accounts receivable:		
Customer, less allowance for doubtful accounts	**82.6**	76.2
Unbilled utility revenues	**62.2**	75.1
Other, less allowance for doubtful accounts	**39.1**	38.2
Production fuel, at weighted average cost	**41.7**	34.2
Materials and supplies, at weighted average cost	**27.5**	25.7
Gas stored underground, at weighted average cost	**20.6**	32.2
Regulatory assets	**45.1**	44.6
Prepaid gross receipts tax	**31.4**	40.2
Prepayments and other	**27.5**	16.9
Total current assets	**379.8**	386.0
Investments:		
Investment in American Transmission Company LLC	**242.3**	238.8
Other	**19.4**	19.8
Total investments	**261.7**	258.6
Other assets:		
Regulatory assets	**331.4**	333.1
Deferred charges and other	**36.6**	44.7
Total other assets	**368.0**	377.8
Total assets	**$ 4,058.5**	$ 4,044.0

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

WISCONSIN POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) (Continued)

	March 31, 2012	December 31, 2011
	(in millions, except per share and share amounts)	
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Wisconsin Power and Light Company common equity:		
Common stock—$5 par value—18,000,000 shares authorized; 13,236,601 shares outstanding	**$ 66.2**	$ 66.2
Additional paid-in capital	**869.1**	869.0
Retained earnings	**510.2**	507.2
Total Wisconsin Power and Light Company common equity	**1,445.5**	1,442.4
Cumulative preferred stock	**60.0**	60.0
Long-term debt, net	**1,082.3**	1,082.2
Total capitalization	**2,587.8**	2,584.6
Current liabilities:		
Commercial paper	**23.3**	25.7
Accounts payable	**85.0**	98.5
Accounts payable to associated companies	**19.0**	20.5
Regulatory liabilities	**38.6**	27.6
Accrued interest	**18.1**	21.6
Derivative liabilities	**31.8**	31.4
Other	**34.2**	32.3
Total current liabilities	**250.0**	257.6
Other long-term liabilities and deferred credits:		
Deferred income taxes	**698.1**	672.5
Regulatory liabilities	**156.8**	161.2
Capital lease obligations—Sheboygan Falls Energy Facility	**102.3**	103.3
Pension and other benefit obligations	**127.6**	128.0
Other	**135.9**	136.8
Total long-term liabilities and deferred credits	**1,220.7**	1,201.8
Total capitalization and liabilities	**$ 4,058.5**	$ 4,044.0

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

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WISCONSIN POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Cash flows from operating activities:		
Net income	**$ 31.9**	$ 44.4
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	**35.8**	33.4
Other amortizations	**11.0**	10.6
Deferred tax expense and investment tax credits	**23.7**	30.8
Equity income from unconsolidated investments	**(10.1)**	(9.4)
Distributions from equity method investments	**8.6**	8.3
Other	**(0.4)**	4.3
Other changes in assets and liabilities:		
Income tax refunds receivable	**(6.4)**	31.4
Production fuel	**(7.5)**	12.2
Gas stored underground	**11.6**	16.4
Regulatory assets	**(9.9)**	7.9
Accounts payable	**(10.7)**	(19.2)
Derivative liabilities	**0.7**	(13.2)
Other	**16.0**	15.5
Net cash flows from operating activities	**94.3**	173.4
Cash flows used for investing activities:		
Utility construction and acquisition expenditures:	**(65.5)**	(124.8)
Other	**1.9**	0.5
Net cash flows used for investing activities	**(63.6)**	(124.3)
Cash flows used for financing activities:		
Common stock dividends	**(28.1)**	(27.7)
Preferred stock dividends	**(0.8)**	(0.8)
Net change in commercial paper	**(2.4)**	(15.0)
Other	**—**	(4.7)
Net cash flows used for financing activities	**(31.3)**	(48.2)
Net increase (decrease) in cash and cash equivalents	**(0.6)**	0.9
Cash and cash equivalents at beginning of period	**2.7**	0.1
Cash and cash equivalents at end of period	**$ 2.1**	$ 1.0
Supplemental cash flows information:		
Cash paid (refunded) during the period for:		
Interest	**$ 23.5**	$ 23.5
Income taxes, net of refunds	**$ 12.2**	($ 33.2)
Significant noncash investing and financing activities:		
Accrued capital expenditures	**$ 16.3**	$ 10.3

The accompanying Combined Notes to Condensed Consolidated Financial Statements are an integral part of these statements.

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ALLIANT ENERGY CORPORATION
INTERSTATE POWER AND LIGHT COMPANY
WISCONSIN POWER AND LIGHT COMPANY
COMBINED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General—The interim condensed consolidated financial statements included herein have been prepared by Alliant Energy, IPL and WPL, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Accordingly, certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the U.S. (GAAP) have been condensed or omitted, although management believes that the disclosures are adequate to make the information presented not misleading. Alliant Energy's condensed consolidated financial statements include the accounts of Alliant Energy and its consolidated subsidiaries (including IPL, WPL, Resources and Alliant Energy Corporate Services, Inc. (Corporate Services)). IPL's condensed consolidated financial statements include the accounts of IPL and its consolidated subsidiary. WPL's condensed consolidated financial statements include the accounts of WPL and its consolidated subsidiary. These financial statements should be read in conjunction with the financial statements and the notes thereto included in Alliant Energy's, IPL's and WPL's latest combined Annual Report on Form 10-K.

In the opinion of management, all adjustments, which unless otherwise noted are normal and recurring in nature, necessary for a fair presentation of the condensed consolidated results of operations for the three months ended March 31, 2012 and 2011, the condensed consolidated financial position at March 31, 2012 and Dec. 31, 2011, and the condensed consolidated statements of cash flows for the three months ended March 31, 2012 and 2011 have been made. Results for the three months ended March 31, 2012 are not necessarily indicative of results that may be expected for the year ending Dec. 31, 2012. A change in management's estimates or assumptions could have a material impact on Alliant Energy's, IPL's and WPL's respective financial condition and results of operations during the period in which such change occurred. Certain prior period amounts have been reclassified on a basis consistent with the current period financial statement presentation. Unless otherwise noted, the notes herein have been revised to exclude discontinued operations and assets and liabilities held for sale for all periods presented.

(b) Regulatory Assets and Regulatory Liabilities -

Regulatory assets were comprised of the following items (in millions):

	Alliant Energy		IPL		WPL	
	March 31, 2012	**Dec. 31, 2011**	**March 31, 2012**	**Dec. 31, 2011**	**March 31, 2012**	**Dec. 31, 2011**
Tax-related	**$ 639.2**	$ 634.7	**$ 618.2**	$ 614.6	**$ 21.0**	$ 20.1
Pension and other postretirement benefits costs	**510.5**	514.1	**263.6**	264.9	**246.9**	249.2
Derivatives	**83.1**	77.7	**38.1**	33.5	**45.0**	44.2
Asset retirement obligations	**57.4**	65.9	**39.7**	48.7	**17.7**	17.2
Environmental-related costs	**37.6**	38.9	**32.6**	32.2	**5.0**	6.7
Emission allowances	**30.0**	30.0	**30.0**	30.0	**—**	—
IPL's electric transmission service costs	**22.9**	24.9	**22.9**	24.9	**—**	—
Debt redemption costs	**21.3**	21.8	**14.7**	15.1	**6.6**	6.7
Other	**87.4**	87.0	**53.1**	53.4	**34.3**	33.6
	$ 1,489.4	$ 1,495.0	**$ 1,112.9**	$ 1,117.3	**$ 376.5**	$ 377.7

Regulatory liabilities were comprised of the following items (in millions):

	Alliant Energy		IPL		WPL	
	March 31, 2012	**Dec. 31, 2011**	**March 31, 2012**	**Dec. 31, 2011**	**March 31, 2012**	**Dec. 31, 2011**
Cost of removal obligations	**$ 407.3**	$ 404.9	**$ 264.7**	$ 261.9	**$ 142.6**	$ 143.0
IPL's tax benefit rider	**329.4**	349.6	**329.4**	349.6	**—**	—
IPL's electric transmission assets sale	**42.8**	45.1	**42.8**	45.1	**—**	—
Energy conservation cost recovery	**37.2**	29.6	**7.0**	4.7	**30.2**	24.9
Commodity cost recovery	**10.5**	23.8	**8.6**	23.2	**1.9**	0.6
Other	**55.3**	57.1	**34.6**	36.8	**20.7**	20.3
	$ 882.5	$ 910.1	**$ 687.1**	$ 721.3	**$ 195.4**	$ 188.8

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IPL's tax benefit rider—Alliant Energy's and IPL's "IPL's tax benefit rider" regulatory liabilities in the above table decreased due to $20 million of regulatory liabilities used to credit IPL's Iowa retail electric customers' bills in the first quarter of 2012. Refer to Note 4 for additional details regarding IPL's tax benefit rider.

(c) Utility Property, Plant and Equipment -

WPL's Edgewater Unit 5 Emission Controls Project—WPL is currently installing a selective catalytic reduction (SCR) system at Edgewater Unit 5 to reduce nitrogen oxide (NOx) emissions at the generating facility. Construction began in the third quarter of 2010 and is expected to be completed by the end of 2012. The SCR is expected to help meet requirements under the Wisconsin Reasonably Available Control Technology (RACT) Rule, which require additional NOx emission reductions at Edgewater by May 2013. As of March 31, 2012, WPL recorded capitalized expenditures of $84 million and allowance for funds used during construction of $5 million for the SCR system in "Construction work in progress—Edgewater Generating Station Unit 5 emission controls" on Alliant Energy's and WPL's Condensed Consolidated Balance Sheets.

Wind Site in Green Lake and Fond du Lac Counties in Wisconsin—In 2009, WPL purchased development rights to an approximate 100 MW wind site in Green Lake and Fond du Lac Counties in Wisconsin. Due to events in the first quarter of 2011 resulting in uncertainty regarding wind siting requirements in Wisconsin and increased risks with permitting this wind site, WPL determined it would be difficult to sell or effectively use the site for wind development. As a result, WPL recognized a $5 million impairment in the first quarter of 2011 for the amount of capitalized costs incurred for this site. The impairment was recorded as a reduction in other utility property, plant and equipment, and a charge to "Utility—other operation and maintenance" in Alliant Energy's and WPL's Condensed Consolidated Statements of Income in the first quarter of 2011.

(d) Comprehensive Income (Loss)—For the three months ended March 31, 2012 and 2011, Alliant Energy had no other comprehensive income; therefore, its comprehensive income was equal to its net income for such periods. For the three months ended March 31, 2012 and 2011, IPL and WPL had no other comprehensive income; therefore their comprehensive income (loss) was equal to their earnings available (loss) for common stock for such periods.

(e) Cash Flows Presentation—Alliant Energy reports cash flows from continuing operations together with cash flows from discontinued operations in its Condensed Consolidated Statements of Cash Flows. Refer to Note 13 for details of cash flows from discontinued operations.

(2) UTILITY RATE CASES

WPL's Retail Fuel-related Rate Case (2012 Test Year)—In December 2011, WPL received an order from the PSCW authorizing an annual retail electric rate increase of $4 million related to expected changes in retail electric production fuel and energy purchases costs (fuel-related costs). The December 2011 order also required WPL to defer direct Cross-State Air Pollution Rule (CSAPR) compliance costs that are not included in the fuel monitoring level and set a zero percent tolerance band for the CSAPR-related deferral. The 2012 fuel-related costs, excluding deferred CSAPR compliance costs, will be monitored using an annual bandwidth of plus or minus 2%. The rate change granted from this request was effective Jan. 1, 2012. Subsequent to the PSCW order issued in December 2011, the U.S. Court of Appeals for the D.C. Circuit stayed the implementation of CSAPR and as a result, the Clean Air Interstate Rule (CAIR) remains effective. Alliant Energy and WPL are currently unable to predict the final outcome of the CSAPR stay and its impact on their financial condition or results of operations.

(3) RECEIVABLES

Sales of Accounts Receivable—IPL maintains a Receivables Purchase and Sale Agreement (Agreement) whereby it may sell its customer accounts receivables, unbilled revenues and certain other accounts receivables to a third-party financial institution through wholly-owned and consolidated special purpose entities. In March 2012, IPL extended through March 2014 the purchase commitment from the third-party financial institution to which it sells its receivables. In exchange for the receivables sold, IPL receives cash proceeds from the third-party financial institution (based on seasonal limits up to $180 million), and deferred proceeds recorded in "Accounts receivable" on Alliant Energy's and IPL's Condensed Consolidated Balance Sheets.

As of March 31, 2012 and Dec. 31, 2011, IPL sold $179.6 million and $195.3 million aggregate amounts of receivables, respectively. IPL's maximum and average outstanding cash proceeds, and costs incurred related to the sales of accounts receivable program for the three months ended March 31 were as follows (in millions):

	2012	2011
Maximum outstanding aggregate cash proceeds (based on daily outstanding balances)	**$ 160.0**	$ 130.0
Average outstanding aggregate cash proceeds (based on daily outstanding balances)	**143.0**	91.4
Costs incurred	**0.4**	0.4

The attributes of IPL's receivables sold under the Agreement were as follows (in millions):

	March 31, 2012	Dec. 31, 2011
Customer accounts receivable	**$ 116.1**	$ 122.4
Unbilled utility revenues	**48.7**	65.4
Other receivables	**14.8**	7.5
Receivables sold	**179.6**	195.3
Less: cash proceeds (a)	**145.0**	140.0
Deferred proceeds	**34.6**	55.3
Less: allowance for doubtful accounts	**1.7**	1.6
Fair value of deferred proceeds	**$ 32.9**	$ 53.7
Outstanding receivables past due	**$ 18.0**	$ 15.9

(a) Changes in cash proceeds during the first quarter of 2012 are recorded in "Sales of accounts receivable" in operating activities in Alliant Energy's and IPL's Condensed Consolidated Statements of Cash Flows.

Additional attributes of IPL's receivables sold under the Agreement for the three months ended March 31 were as follows (in millions):

	2012	2011
Collections reinvested in receivables	**$ 442.3**	$ 475.3
Credit losses, net of recoveries	**2.1**	2.1

(4) INCOME TAXES

Income Tax Rates—The provision for income taxes for earnings from continuing operations is based on an estimated annual effective tax rate that excludes the impact of significant unusual or infrequently occurring items, discontinued operations or extraordinary items. The effective tax rates for Alliant Energy, IPL and WPL differ from the federal statutory rate of 35% generally due to effects of utility rate making, including the tax benefit rider, tax credits, state income taxes and certain non-deductible expenses. Changes in state apportionment rates caused by the planned sale of Alliant Energy's RMT business also impacted the effective tax rates in 2012 for Alliant Energy, IPL and WPL. The income tax rates shown in the following table for the three months ended March 31 were computed by dividing income taxes by income from continuing operations before income taxes.

	2012	2011
Alliant Energy	**39.0%**	22.3%
IPL	**125.4%**	5.9%
WPL	**44.1%**	32.5%

State Apportionment—Alliant Energy, IPL and WPL utilize state apportionment projections to record their deferred tax assets and liabilities each reporting period. Deferred tax assets and liabilities for temporary differences between the tax basis of assets and liabilities and the amounts reported in the consolidated financial statements are recorded utilizing currently enacted tax rates and estimates of future state apportionment rates expected to be in effect at the time the temporary differences reverse. These state apportionment projections are most significantly impacted by the estimated amount of revenues expected in the future from each state jurisdiction for Alliant Energy's consolidated tax group, including both its regulated operations and its non-regulated operations. In the first quarter of 2012, Alliant Energy, IPL and WPL recorded $15.2 million, $8.1 million and $7.0 million, respectively, of deferred income tax expense due to changes in state apportionment projections caused by the planned sale of Alliant Energy's RMT business. These income tax expense amounts recognized in the first quarter of 2012 increased Alliant Energy's, IPL's and WPL's effective income tax rates for continuing operations for such period by 21.4%, 137.3% and 12.3%, respectively.

IPL's Tax Benefit Rider—In January 2011, the Iowa Utilities Board (IUB) approved a tax benefit rider proposed by IPL, which utilizes tax-related regulatory liabilities to credit bills of Iowa retail electric customers beginning in February 2011 to help offset the impact of recent rate increases on such customers. These regulatory liabilities are related to tax benefits from tax accounting method changes for repairs, mixed service costs and allocation of insurance proceeds from the floods in 2008. Alliant Energy's and IPL's effective tax rates for the three months ended March 31, 2012 and 2011 include the impact of reducing income tax expense with offsetting reductions to regulatory liabilities as a result of implementing the tax benefit rider. In the first quarters of 2012 and 2011, $20 million and $7 million, respectively, of tax benefit rider-related regulatory liabilities were used to credit IPL's Iowa retail electric customers' bills. The tax impacts of the tax benefit rider are currently expected to decrease Alliant Energy's and IPL's 2012 annual income tax rates for continuing operations by 12.2% and 37.5%, respectively. In the first quarter of 2011, the tax impacts of the tax benefit rider decreased Alliant Energy's and IPL's income tax rates for continuing operations by 8.9% and 22.9%, respectively.

Production Tax Credits—Alliant Energy has three wind projects that are currently generating production tax credits: WPL's 68 MW Cedar Ridge wind project, which began generating electricity in late 2008; IPL's 200 MW Whispering Willow—East wind project, which began generating electricity in late 2009; and WPL's 200 MW Bent Tree—Phase I wind project, which began generating electricity in late 2010. For the three months ended March 31, production tax credits (net of state tax impacts) resulting from these wind projects were as follows (in millions):

	Alliant Energy		IPL		WPL	
	2012	2011	**2012**	2011	**2012**	2011
Whispering Willow—East (IPL)	**$ 3.6**	$ 2.8	**$ 3.6**	$ 2.8	**$ —**	$ —
Bent Tree—Phase I (WPL)	**1.5**	2.5	**—**	—	**1.5**	2.5
Cedar Ridge (WPL)	**1.3**	1.5	**—**	—	**1.3**	1.5
	$ 6.4	$ 6.8	**$ 3.6**	$ 2.8	**$ 2.8**	$ 4.0

Deferred Tax Assets and Liabilities—In the first quarter of 2012, Alliant Energy's, IPL's and WPL's non-current deferred tax liabilities recognized in "Deferred income taxes" on their Condensed Consolidated Balance Sheets increased $46 million, $18 million and $26 million, respectively. The increases in deferred tax liabilities were primarily related to property-related temporary differences recorded in the first quarter of 2012 from bonus depreciation deductions available in 2012. These items were partially offset by increases in deferred tax assets recorded in the first quarter of 2012 as a result of increasing federal and state net operating loss carryforwards primarily due to such bonus depreciation deductions.

Bonus Depreciation Deductions—In 2010, the Small Business Jobs Act of 2010 (SBJA) and the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (the Act) were enacted. The most significant provisions of the SBJA and the Act for Alliant Energy, IPL and WPL are related to the extension of bonus depreciation deductions for certain expenditures for property that are placed in service through Dec. 31, 2012. Based on capital projects expected to be placed into service in 2012, Alliant Energy currently estimates its total bonus depreciation deductions to be claimed in its 2012 federal income tax return will be approximately $418 million ($114 million for IPL and $203 million for WPL).

Carryforwards—At March 31, 2012, tax carryforwards and associated deferred tax assets and expiration dates were estimated as follows (in millions):

Alliant Energy	Carryforward Amount	Deferred Tax Assets	Earliest Expiration Date
Federal net operating losses	$ 1,043	$ 358	2028
Federal net operating losses offset—uncertain tax positions	(56)	(20)	
State net operating losses	783	41	2014
State net operating losses offset—uncertain tax positions	(28)	(2)	
Federal tax credits	116	114	2022
		$ 491	

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IPL	Carryforward Amount	Deferred Tax Assets	Earliest Expiration Date
Federal net operating losses	$ 475	$ 163	2028
Federal net operating losses offset—uncertain tax positions	(25)	(9)	
State net operating losses	189	11	2022
Federal tax credits	29	29	2022
		$ 194	

WPL	Carryforward Amount	Deferred Tax Assets	Earliest Expiration Date
Federal net operating losses	$ 441	$ 151	2028
Federal net operating losses offset—uncertain tax positions	(31)	(11)	
State net operating losses	148	7	2022
State net operating losses offset—uncertain tax positions	(28)	(2)	
Federal tax credits	30	29	2022
		$ 174	

Uncertain Tax Positions—It is reasonably possible that Alliant Energy, IPL and WPL could have material changes to their unrecognized tax benefits during the 12 months ending March 31, 2013 as a result of the expected issuance in 2012 of revenue procedures clarifying the treatment of repair expenditures for electric generation and gas distribution property. An estimate of the expected changes during the 12 months ending March 31, 2013 cannot be determined at this time.

(5) BENEFIT PLANS

(a) Pension and Other Postretirement Benefits Plans -

Net Periodic Benefit Costs (Credits)—The components of net periodic benefit costs (credits) for Alliant Energy's, IPL's and WPL's sponsored defined benefit pension and other postretirement benefits plans, and defined benefit pension plans amounts directly assigned to IPL and WPL, for the three months ended March 31 are included in the tables below (in millions). In the "IPL" and "WPL" tables below, the qualified defined benefit pension plans costs represent only those respective costs for IPL's and WPL's bargaining unit employees covered under the plans that are sponsored by IPL and WPL, respectively. Also in the "IPL" and "WPL" tables below, the other postretirement benefits plans costs (credits) represent costs (credits) for all IPL and WPL employees, respectively. The "Directly assigned defined benefit pension plans" tables below include amounts directly assigned to each of IPL and WPL related to IPL's and WPL's current and former non-bargaining employees who are participants in Alliant Energy and Corporate Services sponsored qualified and non-qualified defined benefit pension plans.

	Defined Benefit Pension Plans		Other Postretirement Benefits Plans	
Alliant Energy	**2012**	2011	**2012**	2011
Service cost	**$ 3.3**	$ 2.9	**$ 1.7**	$ 2.1
Interest cost	**13.0**	13.0	**2.6**	3.6
Expected return on plan assets	**(17.2)**	(16.0)	**(1.9)**	(1.9)
Amortization of:				
Prior service cost (credit)	**0.1**	0.2	**(3.0)**	(0.7)
Actuarial loss	**8.3**	5.2	**1.6**	1.4
	$ 7.5	$ 5.3	**$ 1.0**	$ 4.5

	Qualified Defined Benefit Pension Plans		Other Postretirement Benefits Plans	
IPL	**2012**	2011	**2012**	2011
Service cost	**$ 1.9**	$ 1.6	**$ 0.8**	$ 0.8
Interest cost	**4.3**	4.2	**1.1**	1.7
Expected return on plan assets	**(5.8)**	(5.0)	**(1.3)**	(1.3)
Amortization of:				
Prior service cost (credit)	**0.1**	0.1	**(1.6)**	(0.3)
Actuarial loss	**2.5**	1.4	**0.9**	0.8
	$ 3.0	$ 2.3	**($ 0.1)**	$ 1.7

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WPL	Qualified Defined Benefit Pension Plan 2012	Qualified Defined Benefit Pension Plan 2011	Other Postretirement Benefits Plans 2012	Other Postretirement Benefits Plans 2011
Service cost	**$ 1.3**	$ 1.2	**$ 0.7**	$ 0.8
Interest cost	**4.1**	4.0	**1.0**	1.4
Expected return on plan assets	**(5.6)**	(5.0)	**(0.3)**	(0.3)
Amortization of:				
Prior service cost (credit)	**0.1**	0.1	**(1.0)**	(0.3)
Actuarial loss	**3.1**	1.8	**0.6**	0.5
	$ 3.0	$ 2.1	**$ 1.0**	$ 2.1

Directly assigned defined benefit pension plans	IPL 2012	IPL 2011	WPL 2012	WPL 2011
Interest cost	**$ 1.8**	$ 1.9	**$ 1.3**	$ 1.4
Expected return on plan assets	**(2.4)**	(2.4)	**(1.8)**	(1.8)
Amortization of:				
Prior service credit	**(0.1)**	(0.1)	**(0.1)**	(0.1)
Actuarial loss	**1.0**	0.7	**0.9**	0.7
	$ 0.3	$ 0.1	**$ 0.3**	$ 0.2

Corporate Services provides services to IPL and WPL, and as a result, IPL and WPL are allocated pension and other postretirement benefits costs associated with Corporate Services employees. The following table includes the allocated qualified and non-qualified pension and other postretirement benefits costs associated with Corporate Services employees providing services to IPL and WPL for the three months ended March 31 (in millions):

	Pension Benefits Costs 2012	Pension Benefits Costs 2011	Other Postretirement Benefits Costs 2012	Other Postretirement Benefits Costs 2011
IPL	**$ 0.5**	$ 0.4	**$ —**	$ 0.4
WPL	**0.3**	0.3	**—**	0.2

Estimated Future and Actual Employer Contributions—Alliant Energy's, IPL's, and WPL's estimated and actual funding for the qualified defined benefit pension, non-qualified defined benefit pension and other postretirement benefits plans, and the directly assigned qualified and non-qualified defined benefit pension plans amounts for 2012 are as follows (in millions):

	Estimated for Calendar Year 2012			Actual Through March 31, 2012		
	Alliant Energy	IPL	WPL	Alliant Energy	IPL	WPL
Qualified defined benefit pension plans	$ —	$ —	$ —	$ —	$ —	$ —
Non-qualified defined benefit pension plans (a)	17.0	N/A	N/A	2.1	N/A	N/A
Directly assigned defined benefit pension plans (b)	N/A	0.8	0.2	N/A	0.2	—
Other postretirement benefits plans	5.4	1.1	3.9	2.2	1.1	1.0

(a) Alliant Energy sponsors several non-qualified defined benefit pension plans that cover certain current and former key employees of IPL and WPL. Alliant Energy allocates pension costs to IPL and WPL for these plans.

(b) Amounts directly assigned to IPL and WPL for non-bargaining employees who are participants in Alliant Energy and Corporate Services sponsored qualified and non-qualified defined benefit pension plans.

Cash Balance Plan—Refer to Note 11(b) for discussion of a class action lawsuit filed against the Cash Balance Plan in 2008 and the Internal Revenue Service (IRS) review of the tax qualified status of the Cash Balance Plan.

401(k) Savings Plans—A significant number of Alliant Energy, IPL and WPL employees participate in defined contribution retirement plans (401(k) savings plans). For the three months ended March 31, Alliant Energy's, IPL's and WPL's costs related to the 401(k) savings plans, which are partially based on the participants' level of contribution, were as follows (in millions):

	Alliant Energy 2012	Alliant Energy 2011	IPL (a) 2012	IPL (a) 2011	WPL (a) 2012	WPL (a) 2011
401(k) costs	**$ 5.2**	$ 5.7	**$ 2.7**	$ 2.9	**$ 2.3**	$ 2.6

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(a) IPL's and WPL's amounts include allocated costs associated with Corporate Services employees.

(b) Equity Incentive Plans—A summary of compensation expense and the related income tax benefits recognized for share-based compensation awards for the three months ended March 31 was as follows (in millions):

	Alliant Energy		IPL		WPL	
	2012	2011	**2012**	2011	**2012**	2011
Compensation expense	**$ 1.6**	$ 2.2	**$ 0.8**	$ 1.2	**$ 0.7**	$ 0.9
Income tax benefits	**0.6**	0.9	**0.3**	0.5	**0.3**	0.4

As of March 31, 2012, total unrecognized compensation cost related to share-based compensation awards was $14.1 million, which is expected to be recognized over a weighted average period of between one and two years. Share-based compensation expense is recognized on a straight-line basis over the requisite service periods and is primarily recorded in "Utility—other operation and maintenance" in the Condensed Consolidated Statements of Income.

In the first quarter of 2012, Alliant Energy granted performance shares, performance units, performance-contingent restricted stock and performance contingent cash awards to certain key employees. Payouts of nonvested awards issued in 2012 are prorated at retirement, death, disability or involuntary termination without cause based on time worked during the first year of the performance period and achievement of the performance criteria. Upon achievement of the performance criteria, payouts of these awards to participants who terminate employment after the first year of the performance period due to retirement, death, disability or involuntary termination without cause are not prorated. Participants' nonvested awards issued in 2012 are forfeited if the participant voluntarily leaves Alliant Energy or is terminated for cause.

Performance Shares and Units—Alliant Energy assumes it will make future payouts of its performance shares and units in cash; therefore, performance shares and units are accounted for as liability awards.

Performance Shares—A summary of the performance shares activity for the three months ended March 31 was as follows:

	2012	2011
	Shares (a)	Shares (a)
Nonvested shares, Jan. 1	**236,979**	234,518
Granted	**45,612**	64,217
Vested (b)	**(111,980)**	(57,838)
Nonvested shares, March 31	**170,611**	240,897

(a) Share amounts represent the target number of performance shares. Each performance share's value is based on the price of one share of Alliant Energy's common stock at the end of the performance period. The actual number of shares that will be paid out upon vesting is dependent upon actual performance and may range from zero to 200% of the target number of shares.

(b) In the first quarter of 2012, 111,980 performance shares granted in 2009 vested at 162.5% of the target, resulting in payouts valued at $8.0 million, which consisted of a combination of cash and common stock (6,399 shares). In the first quarter of 2011, 57,838 performance shares granted in 2008 vested at 75% of the target, resulting in payouts valued at $1.6 million, which consisted of a combination of cash and common stock (1,387 shares).

Performance Units—A summary of the performance unit activity for the three months ended March 31 was as follows:

	2012	2011
	Units (a)	Units (a)
Nonvested units, Jan. 1	**42,996**	23,128
Granted	**24,686**	23,975
Forfeited	**(878)**	(569)
Nonvested units, March 31	**66,804**	46,534

(a) Unit amounts represent the target number of performance units. Each performance unit's value is based on the average price of one share of Alliant Energy's common stock on the grant date of the award. The actual payout for performance units is dependent upon actual performance and may range from zero to 200% of the target number of units.

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Fair Value of Awards—Information related to fair values of nonvested performance shares and units at March 31, 2012, by year of grant, were as follows:

	Performance Shares			Performance Units		
	2012 Grant	2011 Grant	2010 Grant	2012 Grant	2011 Grant	2010 Grant
Nonvested awards	45,612	62,170	62,829	24,686	21,693	20,425
Alliant Energy common stock closing price on March 31, 2012	$ 43.32	$ 43.32	$ 43.32			
Alliant Energy common stock average price on grant date				$ 43.05	$ 38.75	$ 32.56
Estimated payout percentage based on performance criteria	93%	105%	161%	93%	105%	161%
Fair values of each nonvested award	$ 40.29	$ 45.49	$ 69.75	$ 40.04	$ 40.69	$ 52.41

At March 31, 2012, fair values of nonvested performance shares and units were calculated using a Monte Carlo simulation to determine the anticipated total shareowner returns of Alliant Energy and its investor-owned utility peer groups. Expected volatility was based on historical volatilities using daily stock prices over the past three years. Expected dividend yields were calculated based on the most recent quarterly dividend rates announced prior to the measurement date and stock prices at the measurement date. The risk-free interest rate was based on the three-year U.S. Treasury rate in effect as of the measurement date.

Restricted Stock—Restricted stock consists of time-based and performance-contingent restricted stock.

Time-based restricted stock—A summary of the time-based restricted stock activity for the three months ended March 31 was as follows:

	2012		2011	
	Shares	**Weighted Average Fair Value**	Shares	Weighted Average Fair Value
Nonvested shares, Jan. 1	**35,800**	**$ 30.87**	70,033	$ 32.27
Granted	**—**	**—**	5,000	39.86
Vested	**(32,466)**	**29.95**	(33,516)	35.34
Nonvested shares, March 31	**3,334**	**39.86**	41,517	30.71

Performance-contingent restricted stock—A summary of the performance-contingent restricted stock activity for the three months ended March 31 was as follows:

	2012		2011	
	Shares	**Weighted Average Fair Value**	Shares	Weighted Average Fair Value
Nonvested shares, Jan. 1	**301,738**	**$ 32.60**	296,190	$ 32.32
Granted	**45,612**	**43.05**	64,217	38.75
Vested	**(65,172)**	**32.56**	(53,274)	37.93
Forfeited	**(70,527)**	**39.93**	(5,395)	38.00
Nonvested shares, March 31	**211,651**	**32.42**	301,738	32.60

Non-qualified Stock Options—A summary of the stock option activity for the three months ended March 31 was as follows:

	2012		2011	
	Shares	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price
Outstanding, Jan. 1	**63,889**	**$ 24.21**	163,680	$ 24.51
Exercised	**(13,400)**	**24.83**	(20,591)	27.79
Outstanding and exercisable, March 31	**50,489**	**24.04**	143,089	24.04

The weighted average remaining contractual term for options outstanding and exercisable at March 31, 2012 was between one and two years. The aggregate intrinsic value of options outstanding and exercisable at March 31, 2012 was $1.0 million.

Other information related to stock option activity for the three months ended March 31 was as follows (in millions):

	2012	2011
Cash received from stock options exercised	$ 0.3	$ 0.6
Aggregate intrinsic value of stock options exercised	0.2	0.2
Income tax benefit from the exercise of stock options	0.1	0.1

Performance Contingent Cash Awards—A summary of the performance contingent cash awards activity for the three months ended March 31 was as follows:

	2012	2011
	Awards	Awards
Nonvested awards, Jan. 1	46,676	23,428
Granted	36,936	23,975
Vested (a)	(21,605)	—
Forfeited	(1,533)	—
Nonvested awards, March 31	60,474	47,403

(a) In the first quarter of 2012, 21,605 performance contingent cash awards granted in 2010 vested, resulting in cash payouts valued at $0.9 million.

(6) COMMON EQUITY

Common Share Activity—A summary of Alliant Energy's common stock activity during the three months ended March 31, 2012 was as follows:

Shares outstanding, Jan. 1	111,018,821
Equity incentive plans (Note 5(b))	(5,116)
Other (a)	(51,616)
Shares outstanding, March 31	110,962,089

(a) Includes shares transferred from employees to Alliant Energy to satisfy tax withholding requirements in connection with the vesting of certain restricted stock under the equity incentive plans.

Dividend Restrictions—As of March 31, 2012, IPL's amount of retained earnings that were free of dividend restrictions was $323 million. As of March 31, 2012, WPL's amount of retained earnings that were free of dividend restrictions was $84 million for the remainder of 2012.

Restricted Net Assets of Subsidiaries—As of March 31, 2012, the amount of net assets of IPL and WPL that were not available to be transferred to their parent company, Alliant Energy, in the form of loans, advances or cash dividends without the consent of IPL's and WPL's regulatory authorities was $1.0 billion and $1.4 billion, respectively.

Capital Transactions with Subsidiaries—In the first quarter of 2012, IPL and WPL paid common stock dividends of $29.7 million and $28.1 million, respectively, to their parent company.

(7) DEBT

(a) Short-term Debt—Information regarding commercial paper issued under Alliant Energy's, IPL's and WPL's credit facilities classified as short-term debt and other short-term borrowings was as follows (dollars in millions; Not Applicable (N/A)):

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At March 31, 2012	Alliant Energy (Consolidated)	Parent Company	IPL	WPL
Commercial paper:				
Amount outstanding	$ 57.0	$ 33.7	$ —	$ 23.3
Remaining maturity	2 days	2 days	N/A	2 days
Weighted average interest rates	0.3%	0.4%	N/A	0.3%
Available credit facility capacity (a)	$ 918.0	$ 266.3	$ 275.0	$ 376.7

	Alliant Energy		IPL		WPL	
For the quarter ended March 31	**2012**	2011	**2012**	2011	**2012**	2011
Maximum amount outstanding (based on daily outstanding balances)	**$ 102.8**	$ 96.5	**$ 35.4**	$ 12.1	**$ 32.7**	$ 96.5
Average amount outstanding (based on daily outstanding balances)	**$ 66.4**	$ 55.4	**$ 12.8**	$ 1.2	**$ 13.1**	$ 55.4
Weighted average interest rates	**0.3%**	0.3%	**0.4%**	0.3%	**0.2%**	0.3%

(a) Alliant Energy's and IPL's available credit facility capacities reflect outstanding commercial paper classified as both short- and long-term debt at March 31, 2012. Refer to Note 7(b) for further discussion of $25 million of commercial paper outstanding at March 31, 2012 classified as long-term debt.

(b) Long-term Debt—As of March 31, 2012, $25 million of commercial paper was recorded in "Long-term debt, net" on Alliant Energy's and IPL's Condensed Consolidated Balance Sheets due to the existence of long-term credit facilities that back-stop this commercial paper balance, along with Alliant Energy's and IPL's intent and ability to refinance these balances on a long-term basis. As of March 31, 2012, this commercial paper balance had a remaining maturity of 3 days and a 0.4% interest rate.

(8) INVESTMENTS

Unconsolidated Equity Investments—Equity (income) loss from Alliant Energy's and WPL's unconsolidated investments accounted for under the equity method of accounting for the three months ended March 31 was as follows (in millions):

	Alliant Energy		WPL	
	2012	2011	**2012**	2011
American Transmission Company LLC (ATC)	**($ 9.9)**	($ 9.2)	**($ 9.9)**	($ 9.2)
Other	**0.5**	(0.7)	**(0.2)**	(0.2)
	($ 9.4)	($ 9.9)	**($ 10.1)**	($ 9.4)

Summary financial information from the unaudited financial statements of ATC for the three months ended March 31 was as follows (in millions):

	2012	2011
Operating revenues	**$ 147.7**	$ 139.6
Operating income	**78.1**	76.5
Net income	**58.1**	54.2

(9) FAIR VALUE MEASUREMENTS

Fair Value of Financial Instruments—The carrying amounts of Alliant Energy's, IPL's and WPL's current assets and current liabilities approximate fair value because of the short maturity of such financial instruments. Carrying amounts and the related estimated fair values of other financial instruments at March 31, 2012 and Dec. 31, 2011 were as follows (in millions):

	Alliant Energy		IPL		WPL	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
March 31, 2012						
Assets:						
Money market fund investments	**$ 21.3**	**$ 21.3**	**$ 21.3**	**$ 21.3**	**$ —**	**$ —**
Derivative assets (Note 10)	**10.4**	**10.4**	**5.9**	**5.9**	**4.5**	**4.5**
Deferred proceeds (sales of receivables) (Note 3)	**32.9**	**32.9**	**32.9**	**32.9**	**—**	**—**
Capitalization and liabilities:						
Long-term debt (including current maturities) (Note 7(b))	**2,729.6**	**3,317.0**	**1,334.1**	**1,582.0**	**1,082.3**	**1,409.0**
Cumulative preferred stock of subsidiaries	**205.1**	**220.6**	**145.1**	**161.4**	**60.0**	**59.2**
Derivative liabilities (Note 10)	**83.2**	**83.2**	**38.1**	**38.1**	**45.1**	**45.1**
Dec. 31, 2011						
Assets:						
Derivative assets (Note 10)	15.7	15.7	10.6	10.6	5.1	5.1
Deferred proceeds (sales of receivables) (Note 3)	53.7	53.7	53.7	53.7	—	—
Capitalization and liabilities:						
Long-term debt (including current maturities) (Note 7(b))	2,704.5	3,325.3	1,309.0	1,560.4	1,082.2	1,439.0
Cumulative preferred stock of subsidiaries	205.1	222.5	145.1	164.3	60.0	58.2
Derivative liabilities (Note 10)	78.0	78.0	33.6	33.6	44.4	44.4

Valuation Techniques -

Money market fund investments—As of March 31, 2012, money market fund investments were measured at fair value using quoted market prices on listed exchanges.

Derivative assets and derivative liabilities—Alliant Energy, IPL and WPL periodically use derivative instruments for risk management purposes to mitigate exposures to fluctuations in certain commodity prices, transmission congestion costs and currency exchange rates. Alliant Energy, IPL and WPL maintain risk policies that govern the use of derivative instruments. Alliant Energy's, IPL's and WPL's derivative instruments as of March 31, 2012 and Dec. 31, 2011 were not designated as hedging instruments. Alliant Energy's, IPL's and WPL's derivative instruments as of March 31, 2012 and Dec. 31, 2011 included electric physical forward purchase contracts and swap contracts to mitigate pricing volatility for the electricity purchased to supply to IPL's and WPL's customers; electric physical forward sale contracts to offset long positions created by reductions in electricity demand forecasts; natural gas swap contracts to mitigate pricing volatility for the fuel used to supply to the natural gas-fired electric generating facilities they operate; natural gas options to mitigate price increases during periods of high demand or lack of supply; financial transmission rights (FTRs) acquired to manage transmission congestion costs; natural gas physical forward purchase and natural gas option contracts to mitigate pricing volatility for natural gas supplied to IPL's and WPL's retail customers; and natural gas physical purchase and sale contracts to optimize the value of natural gas pipeline capacity.

IPL's and WPL's swap, option and physical forward commodity contracts were non-exchange-based derivative instruments and were valued using indicative price quotations available through a pricing vendor that provides daily exchange forward price settlements, from broker or dealer quotations or from on-line exchanges. The indicative price quotations reflected the average of the bid-ask mid-point prices and were obtained from sources believed to provide the most liquid market for the commodity. IPL and WPL corroborated a portion of these indicative price quotations using quoted prices for similar assets or liabilities in active markets and categorized derivative instruments based on such indicative price quotations as Level 2. IPL's and WPL's commodity contracts that were valued using indicative price quotations based on significant assumptions such as seasonal or monthly shaping and indicative price quotations that could not be readily corroborated were categorized as Level 3. IPL's and WPL's swap, option and physical forward commodity contracts were predominately at liquid trading points. IPL's and WPL's FTRs were measured at fair value each reporting date using monthly or annual auction shadow prices from relevant auctions. Refer to Note 10 for additional details of derivative assets and derivative liabilities.

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Deferred proceeds (sales of receivables)—The fair value of IPL's deferred proceeds related to its sales of receivables program was calculated each reporting date using the cost approach valuation technique. The fair value represents the carrying amount of receivables sold less the allowance for doubtful accounts associated with the receivables sold and cash proceeds received from the receivables sold. Deferred proceeds represent IPL's maximum exposure to loss related to the receivables sold due to the short-term nature of the collection period. Refer to Note 3 for additional information regarding deferred proceeds.

Long-term debt (including current maturities)—For long-term debt instruments that are actively traded, the fair value was based upon quoted market prices for similar liabilities each reporting date. For long-term debt instruments that are not actively traded, the fair value was based on discounted cash flow methodology and utilizes assumptions of current market pricing curves at each reporting date. Refer to Note 7(b) for additional information regarding long-term debt.

Cumulative preferred stock of subsidiaries—The fair value of IPL's 8.375% cumulative preferred stock was based on its closing market price quoted by the New York Stock Exchange on each reporting date. The fair value of WPL's 4.50% cumulative preferred stock was based on the closing market price quoted by the NYSE Amex LLC on each reporting date. The fair value of WPL's remaining preferred stock was calculated based on the market yield of similar securities.

Valuation Hierarchy—Fair value measurement accounting establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The three levels of the fair value hierarchy and examples of each are as follows:

Level 1—Pricing inputs are quoted prices available in active markets for identical assets or liabilities as of the reporting date. As of March 31, 2012, Level 1 items included money market fund investments, IPL's 8.375% cumulative preferred stock and WPL's 4.50% cumulative preferred stock.

Level 2—Pricing inputs are quoted prices for similar assets or liabilities in active markets or quoted prices for identical or similar assets or liabilities in markets that are not active as of the reporting date. As of March 31, 2012 and Dec. 31, 2011, Level 2 items included IPL's and WPL's non-exchange traded commodity contracts. Level 2 items as of March 31, 2012 also included the remainder of WPL's cumulative preferred stock and substantially all of the long-term debt instruments.

Level 3—Pricing inputs are unobservable inputs for assets or liabilities for which little or no market data exist and require significant management judgment or estimation. As of March 31, 2012 and Dec. 31, 2011, Level 3 items included IPL's deferred proceeds, and IPL's and WPL's FTRs and certain commodity contracts.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. Items subject to fair value measurement disclosure requirements were as follows (Not Applicable (N/A); in millions):

	March 31, 2012				Dec. 31, 2011			
Alliant Energy	**Fair Value**	**Level 1**	**Level 2**	**Level 3**	Fair Value	Level 1	Level 2	Level 3
Assets:								
Money market fund investments	**$ 21.3**	**21.3**	**$ —**	**$ —**	$ —	$ —	$ —	$ —
Derivatives—commodity contracts	**10.4**	**—**	**4.9**	**5.5**	15.7	—	3.4	12.3
Deferred proceeds	**32.9**	**—**	**—**	**32.9**	53.7	—	—	53.7
Capitalization and liabilities:								
Long-term debt (including current maturities)	**3,317.0**	**—**	**3,316.5**	**0.5**	N/A	N/A	N/A	N/A
Cumulative preferred stock of subsidiaries	**220.6**	**171.1**	**49.5**	**—**	N/A	N/A	N/A	N/A
Derivatives—commodity contracts	**83.2**	**—**	**62.6**	**20.6**	78.0	—	64.8	13.2

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IPL	March 31, 2012 Fair Value	Level 1	Level 2	Level 3	Dec. 31, 2011 Fair Value	Level 1	Level 2	Level 3
Assets:								
Money market fund investments	**$ 21.3**	**$ 21.3**	**$ —**	**$ —**	$ —	$ —	$ —	$ —
Derivatives—commodity contracts	**5.9**	**—**	**2.3**	**3.6**	10.6	—	1.3	9.3
Deferred proceeds	**32.9**	**—**	**—**	**32.9**	53.7	—	—	53.7
Capitalization and liabilities:								
Long-term debt	**1,582.0**	**—**	**1,582.0**	**—**	N/A	N/A	N/A	N/A
Cumulative preferred stock	**161.4**	**161.4**	**—**	**—**	N/A	N/A	N/A	N/A
Derivatives—commodity contracts	**38.1**	**—**	**23.1**	**15.0**	33.6	—	28.6	5.0

WPL	March 31, 2012 Fair Value	Level 1	Level 2	Level 3	Dec. 31, 2011 Fair Value	Level 1	Level 2	Level 3
Assets:								
Derivatives—commodity contracts	**$ 4.5**	**$ —**	**$ 2.6**	**$ 1.9**	$ 5.1	$ —	$ 2.1	$ 3.0
Capitalization and liabilities:								
Long-term debt	**1,409.0**	**—**	**1,409.0**	**—**	N/A	N/A	N/A	N/A
Cumulative preferred stock	**59.2**	**9.7**	**49.5**	**—**	N/A	N/A	N/A	N/A
Derivatives—commodity contracts	**45.1**	**—**	**39.5**	**5.6**	44.4	—	36.2	8.2

In accordance with IPL's and WPL's fuel and natural gas recovery mechanisms, prudently incurred costs from derivative instruments are recovered from customers in the future after any losses are realized. Based on these recovery mechanisms, the changes in the fair value of derivative liabilities resulted in comparable changes to regulatory assets and the changes in the fair value of derivative assets resulted in comparable changes to regulatory liabilities on the Condensed Consolidated Balance Sheets.

The significant unobservable inputs (Level 3 inputs) used in the fair value measurement of IPL's and WPL's commodity contracts are forecasted electricity and natural gas prices, and the expected volatility of such prices. Significant changes in any of those inputs would result in a significantly lower or higher fair value measurement. Information for fair value measurements using significant unobservable inputs (Level 3 inputs) for the three months ended March 31 was as follows (in millions):

	Derivative Assets and (Liabilities), net					
	Commodity Contracts		Foreign Contracts		Deferred Proceeds	
Alliant Energy	**2012**	2011	**2012**	2011	**2012**	2011
Beginning balance, Jan. 1	**($ 0.9)**	$ 2.8	**$ —**	$ 4.7	**$ 53.7**	$152.9
Total losses (realized/unrealized) included in changes in net assets (a)	**(12.5)**	(0.5)	**—**	—	**—**	—
Transfers into Level 3 (b)	**(3.8)**	—	**—**	—	**—**	—
Transfers out of Level 3 (c)	**5.3**	—	**—**	—	**—**	—
Settlements (d)	**(3.2)**	(3.4)	**—**	(2.6)	**(20.8)**	(23.1)
Ending balance, March 31	**($ 15.1)**	($ 1.1)	**$ —**	$ 2.1	**$ 32.9**	$129.8
The amount of total losses for the period included in changes in net assets attributable to the change in unrealized losses relating to assets and liabilities held at March 31 (a)	**($ 12.5)**	($ 0.5)	**$ —**	$ —	**$ —**	$ —

IPL	Derivative Assets and (Liabilities), net: Commodity Contracts 2012	Commodity Contracts 2011	Foreign Contracts 2012	Foreign Contracts 2011	Deferred Proceeds 2012	Deferred Proceeds 2011
Beginning balance, Jan. 1	**$ 4.3**	$ 4.3	**$ —**	$ 4.8	**$ 53.7**	$152.9
Total losses (realized/unrealized) included in changes in net assets (a)	**(10.8)**	(0.2)	**—**	—	**—**	—
Transfers into Level 3 (b)	**(2.7)**	—	**—**	—	**—**	—
Transfers out of Level 3 (c)	**0.1**	—	**—**	—	**—**	—
Settlements (d)	**(2.3)**	(2.7)	**—**	(2.7)	**(20.8)**	(23.1)
Ending balance, March 31	**($ 11.4)**	$ 1.4	**$ —**	$ 2.1	**$ 32.9**	$129.8
The amount of total losses for the period included in changes in net assets attributable to the change in unrealized losses relating to assets and liabilities held at March 31 (a)	**($ 10.8)**	($ 0.2)	**$ —**	$ —	**$ —**	$ —

WPL	Derivative Assets and (Liabilities), net: Commodity Contracts 2012	Commodity Contracts 2011	Foreign Contracts 2012	Foreign Contracts 2011
Beginning balance, Jan. 1	**($ 5.2)**	($ 1.5)	**$ —**	($ 0.1)
Total losses (realized/unrealized) included in changes in net assets (a)	**(1.7)**	(0.3)	**—**	—
Transfers into Level 3 (b)	**(1.1)**	—	**—**	—
Transfers out of Level 3 (c)	**5.2**	—	**—**	—
Settlements	**(0.9)**	(0.7)	**—**	0.1
Ending balance, March 31	**($ 3.7)**	($ 2.5)	**$ —**	$ —
The amount of total losses for the period included in changes in net assets attributable to the change in unrealized losses relating to assets and liabilities held at March 31 (a)	**($ 1.7)**	($ 0.3)	**$ —**	$ —

(a) Losses related to derivative assets and derivative liabilities are recorded in "Regulatory assets" and "Regulatory liabilities" on the Condensed Consolidated Balance Sheets.

(b) Markets for similar assets and liabilities were not active and observable market inputs were not available for transfers into Level 3. The transfers were valued as of the beginning of the period.

(c) Observable market inputs became available for certain commodity contracts previously classified as Level 3 for transfers out of Level 3. The transfers were valued as of the beginning of the period.

(d) Settlements related to deferred proceeds are due to the change in the carrying amount of receivables sold less the allowance for doubtful accounts associated with the receivables sold and cash proceeds received from the receivables sold.

Electric and Natural Gas Commodity Contracts—As of March 31, 2012, the fair values of Alliant Energy's, IPL's and WPL's electric and natural gas commodity contracts classified as Level 3, excluding FTRs, were recognized as net derivative liabilities of $18.4 million, $14.3 million and $4.1 million, respectively. These commodity contracts were valued using a market approach technique that utilizes significant observable inputs to estimate forward commodity prices. Forward electric prices are estimated using market information obtained from counterparties and brokers, including bids, offers, historical transactions (including historical price differences between locations with both observable and unobservable prices) and executed trades. Forward natural gas prices are estimated using the most recent quoted observable inputs applied to future months (including historical price differences between locations with both observable and unobservable prices). Observable inputs are obtained from compiled third-party pricing data sources and include bids, offers, historical transactions and executed trades. Forward electric price commodity curves that extend beyond currently available observable inputs utilize market prices for the most recent period for which observable inputs are available. Observable inputs include bids, offers, historical transactions and executed trades.

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FTRs—As of March 31, 2012, Alliant Energy's, IPL's and WPL's FTRs classified as Level 3 were recognized as net derivative assets of $3.3 million, $2.9 million and $0.4 million, respectively. These FTRs were measured at fair value using monthly or annual auction shadow prices for identical or similar instruments from relevant closed auctions.

(10) DERIVATIVE INSTRUMENTS

Commodity Derivatives—

Purpose—Alliant Energy, IPL and WPL periodically use derivative instruments for risk management purposes to mitigate exposures to fluctuations in certain commodity prices and transmission congestion costs. Refer to Note 9 for detailed discussion of Alliant Energy's, IPL's and WPL's derivative instruments as of March 31, 2012 and Dec. 31, 2011.

Notional Amounts—As of March 31, 2012, notional amounts by delivery year related to outstanding swap contracts, option contracts, physical forward contracts and FTRs that were accounted for as commodity derivative instruments were as follows (units in thousands):

	2012	2013	2014	Total
Alliant Energy				
Electricity (megawatt-hours (MWhs))	3,994	3,530	509	8,033
FTRs (MWs)	8	—	—	8
Natural gas (dekatherms (Dths))	41,958	20,460	4,145	66,563
IPL				
Electricity (MWhs)	2,416	1,725	71	4,212
FTRs (MWs)	5	—	—	5
Natural gas (Dths)	26,291	9,237	1,420	36,948
WPL				
Electricity (MWhs)	1,578	1,805	438	3,821
FTRs (MWs)	3	—	—	3
Natural gas (Dths)	15,667	11,223	2,725	29,615

The notional amounts in the above table were computed by aggregating the absolute value of purchase and sale positions within commodities for each delivery year.

Financial Statement Presentation—Alliant Energy, IPL and WPL record derivative instruments at fair value each reporting date on the balance sheet as assets or liabilities. At March 31, 2012 and Dec. 31, 2011, the fair values of current derivative assets were included in "Prepayments and other," non-current derivative assets were included in "Deferred charges and other," current derivative liabilities were included in "Derivative liabilities" and non-current derivative liabilities were included in "Other long-term liabilities and deferred credits" on the Condensed Consolidated Balance Sheets as follows (in millions):

	Alliant Energy		IPL		WPL	
Commodity contracts	**March 31, 2012**	Dec. 31, 2011	**March 31, 2012**	Dec. 31, 2011	**March 31, 2012**	Dec. 31, 2011
Current derivative assets	**$ 5.6**	$ 12.7	**$ 3.9**	$ 9.2	**$ 1.7**	$ 3.5
Non-current derivative assets	**4.8**	3.0	**2.0**	1.4	**2.8**	1.6
Current derivative liabilities	**61.9**	55.9	**30.1**	24.5	**31.8**	31.4
Non-current derivative liabilities	**21.3**	22.1	**8.0**	9.1	**13.3**	13.0

Alliant Energy, IPL and WPL generally record gains and losses from IPL's and WPL's derivative instruments with offsets to regulatory assets or regulatory liabilities, based on their fuel and natural gas cost recovery mechanisms, as well as other specific regulatory authorizations. For the three months ended March 31, 2012 and 2011, gains and losses from commodity derivative instruments not designated as hedging instruments were recorded as follows (in millions):

Location Recorded on Balance Sheets	Gains (Losses)					
	Alliant Energy		IPL		WPL	
	2012	2011	**2012**	2011	**2012**	2011
Regulatory assets	**($39.7)**	($4.0)	**($22.2)**	($2.4)	**($17.5)**	($1.6)
Regulatory liabilities	**1.4**	1.5	**—**	0.8	**1.4**	0.7

Losses from commodity contracts during the three months ended March 31, 2012 were primarily due to impacts of decreases in electricity and natural gas prices during such period.

Credit Risk-related Contingent Features—Alliant Energy, IPL and WPL have entered into various agreements that contain credit risk-related contingent features including requirements for them to maintain certain credit ratings from each of the major credit rating agencies and limitations on their liability positions under the various agreements based upon their credit ratings. In the event of a downgrade in their credit ratings or if their liability positions exceed certain contractual limits, Alliant Energy, IPL or WPL may need to provide credit support in the form of letters of credit or cash collateral up to the amount of their exposure under the contracts, or may need to unwind the contracts and pay the underlying liability positions.

Certain of these agreements with credit risk-related contingency features are accounted for as derivative instruments. The aggregate fair value of all derivatives with credit risk-related contingent features that were in a net liability position on March 31, 2012 was $83.2 million, $38.1 million and $45.1 million for Alliant Energy, IPL and WPL, respectively. At March 31, 2012, Alliant Energy, IPL and WPL all had investment-grade credit ratings. However, IPL exceeded its liability position with one counterparty requiring it to post $1.0 million of cash collateral. If the most restrictive credit risk-related contingent features for derivative agreements in a net liability position were triggered on March 31, 2012, Alliant Energy, IPL and WPL would be required to post an additional $82.2 million, $37.1 million and $45.1 million, respectively, of credit support to their counterparties.

(11) COMMITMENTS AND CONTINGENCIES

(a) Operating Expense Purchase Obligations—Alliant Energy, IPL and WPL have entered into various commodity supply, transportation and storage contracts to meet their obligations to deliver electricity and natural gas to IPL's and WPL's utility customers. Alliant Energy, IPL and WPL also enter into other operating expense purchase obligations with various vendors for other goods and services. At March 31, 2012, minimum future commitments related to these operating expense purchase obligations were as follows (in millions):

	Alliant Energy	IPL	WPL
Purchased power (a):			
Duane Arnold Energy Center (DAEC) (IPL)	$ 364	$ 364	$ —
Kewaunee Nuclear Power Plant (Kewaunee) (WPL)	131	—	131
Other	41	9	32
	536	373	163
Natural gas	255	120	135
Coal (b)	274	88	61
Sulfur dioxide (SO2) emission allowances	34	34	—
Other (c)	41	19	22
	$ 1,140	$ 634	$ 381

(a) Includes payments required by purchased power agreements (PPAs) for capacity rights and minimum quantities of MWhs required to be purchased. Excludes contracts that are considered operating leases.

(b) Corporate Services entered into system-wide coal contracts on behalf of IPL and WPL that include minimum future commitments of $125 million that have not been directly assigned to IPL and WPL since the specific needs of each utility were not yet known as of March 31, 2012.

(c) Includes individual commitments incurred during the normal course of business that exceeded $1 million at March 31, 2012.

(b) Legal Proceedings—

Air Permitting Violation Claims—In September 2010, Sierra Club filed in the U.S. District Court for the Western District of Wisconsin a complaint against WPL, as owner and operator of the Nelson Dewey Generating Station (Nelson Dewey) and the Columbia Energy Center (Columbia), based on allegations that modifications were made at the facilities without complying with the Prevention of Significant Deterioration (PSD) program requirements, Title V Operating Permit requirements of the Clean Air Act (CAA) and state regulatory counterparts contained within the Wisconsin state implementation plan (SIP) designed to implement the CAA. In October 2010, WPL responded to these claims related to Nelson Dewey and Columbia by filing with the U.S. District Court an answer denying the Columbia allegations and a motion to dismiss the Nelson Dewey allegations based on statute of limitations arguments. In November 2010, WPL filed a motion to dismiss the Nelson Dewey and Columbia allegations based on lack of jurisdiction. Sierra Club has responded to the motions. In January 2012, the Court reset the trial date to Dec. 10, 2012 and scheduled a status conference for Feb. 15, 2012 to receive an update on settlement progress. At the Feb. 15, 2012 status conference, the Court reaffirmed the Dec. 10, 2012 trial date and set a pre-trial schedule that allows the parties to work toward settlement.

In September 2010, Sierra Club filed in the U.S. District Court for the Eastern District of Wisconsin a complaint against WPL, as owner and operator of the Edgewater Generating Station (Edgewater), which contained similar allegations regarding air permitting violations at Edgewater. In the Edgewater complaint, additional allegations were made regarding violations of emission limits for visible emissions. In February 2011, WPL responded to these claims related to Edgewater by filing with the U.S. District Court an answer denying the allegations and a motion to dismiss the allegations based on lack of jurisdiction. In December 2011, the Court stayed all discovery and scheduling deadlines for 60 days (through Feb. 15, 2012) so that the Parties may continue settlement negotiations. In February 2012, the Court extended the stay. In April 2012, WPL and Sierra Club filed a joint settlement status report requesting the Court to stay all case management deadlines and agreeing to file a settlement status report by July 15, 2012, if no consent decree is filed by that date. WPL and Sierra Club are currently engaged in settlement discussions regarding the Nelson Dewey, Columbia and Edgewater air permitting violation claims.

In 2009, the EPA sent a Notice of Violation (NOV) to WPL as an owner and the operator of Edgewater, Nelson Dewey and Columbia. The NOV alleges that the owners failed to comply with appropriate pre-construction review and permitting requirements and as a result violated the PSD program requirements, Title V Operating Permit requirements of the CAA and the Wisconsin SIP. WPL is engaged in settlement negotiations with the EPA in conjunction with the settlement negotiations with the Sierra Club discussed above.

In response to similar EPA CAA enforcement initiatives, certain utilities have elected to settle with the EPA, while others have elected to litigate. If the EPA and/or Sierra Club successfully prove their claims that projects completed in the past at Edgewater, Nelson Dewey and Columbia required either a state or federal CAA permit, WPL may, under the applicable statutes, be required to pay civil penalties in amounts of up to $37,500 per day for each violation and/or complete actions for injunctive relief. Payment of fines and/or injunctive relief could be included in a settlement outcome. Injunctive relief contained in settlements or court-ordered remedies for other utilities required the installation of emission control technology, changed operating conditions including use of alternative fuels other than coal, caps for emissions and limitations on generation including retirement of generating units, and other beneficial environmental projects. If similar remedies are required for final resolution of these matters at Edgewater, Nelson Dewey and Columbia, Alliant Energy and WPL would incur additional capital and operating expenditures. Alliant Energy and WPL are continuing to analyze the allegations and are unable to predict the impact of the allegations on their financial condition or results of operations, but believe that the outcome could be significant. WPL and the other owners of Edgewater and Columbia are exploring settlement options while simultaneously defending against these allegations. Alliant Energy and WPL believe the projects at Edgewater, Nelson Dewey and Columbia were routine or not projected to increase emissions and therefore did not violate the permitting requirements of the CAA.

Alliant Energy and WPL do not currently believe any material losses from these air permitting violation claims are both probable and reasonably estimated and therefore have not recognized any material related loss contingency amounts as of March 31, 2012. Alliant Energy and WPL are not able to estimate the possible loss or range of possible loss related to these air permit violation claims given the various litigation and settlement scenarios being pursued to resolve this contingency as well as uncertainty regarding which, if any, allegations will be determined to be violations and the nature and cost of any fines and injunctive relief that could be required to resolve any violations.

<u>Alliant Energy Cash Balance Pension Plan (Plan)</u>—In February 2008, a class action lawsuit was filed against the Plan in the U.S. District Court for the Western District of Wisconsin (Court). The complaint alleged that certain Plan participants who received distributions prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of ERISA because the Plan applied an improper interest crediting rate to project the cash balance account to their normal retirement age. These Plan participants were limited to individuals who, prior to normal retirement age, received a lump sum distribution or an annuity payment. The Court certified two subclasses of plaintiffs that in aggregate include all persons vested or partially vested in the Plan who received these distributions from Jan. 1, 1998 to Aug. 17, 2006 including: (1) persons who received distributions from Jan. 1, 1998 through Feb. 28, 2002; and (2) persons who received distributions from March 1, 2002 to Aug. 17, 2006.

In June 2010, the Court issued an opinion and order that granted the plaintiffs' motion for summary judgment on liability in the lawsuit and decided with respect to damages that prejudgment interest on damages would be allowed. In December 2010, the Court issued an opinion and order that decided the interest crediting rate that the Plan used to project the cash balance accounts of the plaintiffs during the class period should have been 8.2% and that a pre-retirement mortality discount would not be applied to the damages calculation. In March 2011, the Court issued an opinion and order that prejudgment interest on damages would be calculated using the average prime rate from the date that the Plan failed to make the total payment to a particular participant through the date of the final judgment (which has not yet been issued). In September 2011, plaintiffs filed a motion for leave to file a supplemental complaint to assert that the 2011 amendment to the Plan, made to conform with the IRS determination letter (described below), was itself an ERISA violation. In November 2011, the Court allowed the filing of the plaintiffs' supplemental complaint and denied a separate motion for reconsideration filed by the Plan arguing that certain of plaintiffs' claims were time-barred. Following the November 2011 ruling, plaintiffs filed a supplemental complaint and the Plan filed an answer and an amended answer. In March 2012, the Plan and the plaintiffs each filed motions for summary judgment related to the supplemental complaint, and the plaintiffs filed a motion for class certification, seeking to amend the class definition and for reappointment of class representatives and class counsel. In April 2012, both the Plan and the plaintiffs filed briefs opposing the other party's motion for summary judgment. The Plan also filed a brief opposing the plaintiffs' motion for class certification.

Based on opinions and orders issued by the Court to date and the $10.2 million of IRS-related offset benefits paid by the Plan in 2011, the Plan currently estimates that the trial court judgment of damages, after offsetting the additional benefits paid to participants by the Plan, will be at least $17 million, which includes prejudgment interest through March 31, 2012, but does not include any award for plaintiffs' attorney's fees or costs. The trial court judgment of damages related to the additional claims newly asserted in the supplemental complaint by the plaintiffs in November 2011 is uncertain. Following resolution of the supplemental complaint, the Plan may appeal the trial court judgment of damages to the Seventh Circuit Court of Appeals. As a result, Alliant Energy, IPL and WPL do not currently believe any material losses related to the final judgment of damages from this class action lawsuit are both probable and reasonably estimated, and therefore have not recognized any material loss contingency amounts for the final judgment of damages as of March 31, 2012. Alliant Energy, IPL and WPL are currently unable to predict the final outcome of the class action lawsuit or the ultimate impact on their financial condition or results of operations but believe the outcome could have a material effect on their retirement plan funding and expense.

The IRS also considered the interest crediting rate used to project the cash balance account to participants' normal retirement age as part of its review of Alliant Energy's request for a favorable determination letter with respect to the tax-qualified status of the Plan. Alliant Energy reached an agreement with the IRS, which resulted in a favorable determination letter for the Plan in 2011. The agreement with the IRS required Alliant Energy to amend the Plan in 2011 resulting in $10.2 million of aggregate additional benefits paid by Alliant Energy to certain former participants in the Plan in 2011. The $10.2 million of aggregate payments by Alliant Energy are an offset against any final judgment of damages by the Court in the case discussed above, in whole or in part, depending on the scope of the final judgment.

<u>RMT Contract Disputes</u>—In September 2011, RMT filed a lawsuit in the U.S. District Court for the Western District of Wisconsin alleging, among other things, breach of contract against Cable System Installation (CSI), a subcontractor to RMT on several solar projects in New Jersey. The complaint alleges that CSI breached its contract with RMT by failing to complete the work, by failing to complete the work in a timely manner, by failing to perform work according to the contract, for abandonment of work, and for other related claims. RMT incurred additional costs to replace CSI and to complete CSI's work with alternative subcontractors, incurred liquidated damages assessed by the project owners due to project delays, and had liens filed by CSI's vendors that CSI has not paid. The lawsuit seeks to recover all costs incurred by RMT as a result of the breaches of contract by CSI. CSI filed an answer and counterclaims against RMT asserting that RMT owes CSI additional amounts for work performed under the contract that have not been paid to date. CSI also filed a motion requesting the case be transferred to New Jersey. CSI has filed liens against the projects based on claims that they have not been paid for work performed under the contract with RMT and vendors of CSI have filed liens against the projects based on claims that they have not been paid as required under their agreements with CSI. Two vendors of CSI have also filed lawsuits in New Jersey including claims against both CSI and RMT resulting from work allegedly performed by the two vendors but not paid by CSI or RMT. As of March 31, 2012, RMT has posted bonds of $17 million to discharge the liens filed against the New Jersey project sites by CSI and CSI's vendors. Alliant Energy does not currently believe any material losses from these claims are both probable and reasonably estimated and therefore has not recognized any material related loss contingency amounts as of March 31, 2012. Alliant Energy is currently not able to estimate the possible loss or range of possible loss related to these claims given the early state of the lawsuits. Alliant Energy also has not recognized any material benefits from the lawsuit filed by RMT against CSI as of March 31, 2012.

(c) Guarantees and Indemnifications—Alliant Energy provided an indemnification associated with the 2007 sale of its Mexico business for losses resulting from potential breach of the representations and warranties made by Alliant Energy on the sale date and for the breach of its obligations under the sale agreement. The indemnification has a maximum limit of $20 million and expires in June 2012. Alliant Energy believes the likelihood of having to make any material cash payments under this indemnification is remote. Alliant Energy has not recognized any material liabilities related to this indemnification as of March 31, 2012.

Alliant Energy also continues to guarantee the abandonment obligations of Whiting Petroleum Corporation (Whiting) under the Point Arguello partnership agreements following the sale of Alliant Energy's remaining interest in Whiting in 2004. The guarantee does not include a maximum limit. As of March 31, 2012, the present value of the abandonment obligations is estimated at $29 million. Alliant Energy believes that no payments will be made under this guarantee. Alliant Energy has not recognized any material liabilities related to this guarantee as of March 31, 2012.

RMT provides renewable energy services to clients throughout the U.S., including facility siting, permitting, design, procurement, construction and high voltage connection services for wind and solar projects. Alliant Energy has guaranteed RMT's performance obligations related to certain of these projects. As of March 31, 2012, Alliant Energy had $609 million of performance guarantees outstanding with $101 million, $325 million and $183 million expiring in 2012, 2013 and 2014, respectively. RMT has also provided surety bonds in support of the payment and performance obligations of certain of these projects and Alliant Energy has guaranteed RMT's indemnity obligations to the surety company. As of March 31, 2012, Alliant Energy had $114 million in surety bonds and related Alliant Energy performance guarantees outstanding with $112 million expiring in 2012 and $2 million expiring in 2013. Alliant Energy currently believes that no material cash payments will be made under any of these obligations. Alliant Energy has not recognized any material liabilities related to these obligations as of March 31, 2012.

(d) Environmental Matters—

Manufactured Gas Plant (MGP) Sites—IPL and WPL have current or previous ownership interests in 40 and 14 sites, respectively, previously associated with the production of gas for which they may be liable for investigation, remediation and monitoring costs. IPL and WPL have received letters from state environmental agencies requiring no further action at 11 and 9 of these sites, respectively. Additionally, IPL has met state environmental agency expectations at 3 additional sites requiring no further action for soil remediation. IPL and WPL are working pursuant to the requirements of various federal and state agencies to investigate, mitigate, prevent and remediate, where necessary, the environmental impacts to property, including natural resources, at and around the sites in order to protect public health and the environment.

Alliant Energy, IPL and WPL record environmental liabilities related to these MGP sites based upon periodic studies. Such amounts are based on the best current estimate of the remaining amount to be incurred for investigation, remediation and monitoring costs for those sites where the investigation process has been or is substantially completed, and the minimum of the estimated cost range for those sites where the investigation is in its earlier stages. There are inherent uncertainties associated with the estimated remaining costs for MGP projects primarily due to unknown site conditions and potential changes in regulatory agency requirements. It is possible that future cost estimates will be greater than current estimates as the investigation process proceeds and as additional facts become known. The amounts recognized as liabilities are reduced for expenditures incurred and are adjusted as further information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted. Management currently estimates the range of remaining costs to be incurred for the investigation, remediation and monitoring of these sites to be $21 million ($18 million for IPL and $3 million for WPL) to $45 million ($41 million for IPL and $4 million for WPL). At March 31, 2012, Alliant Energy, IPL and WPL recorded $31 million, $28 million and $3 million, respectively, in current and non-current environmental liabilities for their remaining costs to be incurred for these MGP sites.

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Other Environmental Contingencies—In addition to the environmental liabilities discussed above, Alliant Energy, IPL and WPL are also monitoring various environmental regulations that may have a significant impact on their future operations. Given uncertainties regarding the outcome, timing and compliance plans for these environmental matters, Alliant Energy, IPL and WPL are currently not able to determine the complete financial impact of these regulations but do believe that future capital investments and/or modifications to their electric generating facilities to comply with these regulations could be significant. Specific current, proposed or potential environmental matters that may require significant future expenditures by Alliant Energy, IPL and WPL include, among others: CAIR, CSAPR, Clean Air Visibility Rule, Utility Maximum Achievable Control Technology (MACT) Rule, Wisconsin State Mercury Rule, Wisconsin RACT Rule, Ozone National Ambient Air Quality Standards (NAAQS) Rule, Fine Particle NAAQS Rule, Nitrogen Dioxide NAAQS Rule, SO2 NAAQS Rule, Industrial Boiler and Process Heater MACT Rule, Federal Clean Water Act including Section 316(b), Wisconsin and Iowa State Thermal Rules, Hydroelectric Fish Passage Device, Coal Combustion Residuals, Polychlorinated Biphenyls, and various legislation and EPA regulations to monitor and regulate the emission of greenhouse gases (GHG) including the EPA New Source Performance Standard (NSPS) for GHG Emissions from Electric Utilities and the EPA GHG Tailoring Rule. Some recent developments concerning these environmental matters are included below:

Water Quality—

Hydroelectric Fish Passages Device—In March 2012, the Federal Energy Regulatory Commission (FERC) extended the deadline to install an agency-approved fish passage device at WPL's Prairie du Sac hydro plant to July 1, 2015.

GHG Emissions—

EPA NSPS for GHG Emissions from Electric Utilities—In April 2012, the EPA published proposed NSPS for GHG, including carbon dioxide (CO_2) emissions from new fossil-fueled electric generating units (EGUs) larger than 25 MW with an output-based emissions rate limitation of 1,000 pounds of CO_2 per MWh. This emissions rate limitation is expected to be effective upon the EPA's issuance of the final rule in the second quarter of 2013.

(12) SEGMENTS OF BUSINESS

Alliant Energy—Certain financial information relating to Alliant Energy's business segments is as follows. As of March 31, 2012, Alliant Energy's RMT business qualified as assets and liabilities held for sale. The operating results of RMT have been separately classified and reported as discontinued operations in Alliant Energy's Condensed Consolidated Statements of Income. As a result, Alliant Energy no longer reports "Non-regulated—RMT" segment information. Intersegment revenues were not material to Alliant Energy's operations.

	Utility				Non-Regulated,	Alliant Energy
	Electric	Gas	Other	Total	Parent and Other	Consolidated
				(in millions)		
Three Months Ended March 31, 2012						
Operating revenues	**$ 572.4**	**$ 167.1**	**$ 13.7**	**$ 753.2**	**$ 12.5**	**$ 765.7**
Operating income	**59.1**	**27.7**	**1.7**	**88.5**	**7.1**	**95.6**
Amounts attributable to Alliant Energy common shareowners:						
Income from continuing operations, net of tax				**26.4**	**12.9**	**39.3**
Loss from discontinued operations, net of tax				**—**	**(4.4)**	**(4.4)**
Net income attributable to Alliant Energy common shareowners				**26.4**	**8.5**	**34.9**
Three Months Ended March 31, 2011						
Operating revenues	620.3	229.0	16.7	866.0	11.2	877.2
Operating income (loss)	89.3	35.9	(3.3)	121.9	5.4	127.3
Amounts attributable to Alliant Energy common shareowners:						
Income from continuing operations, net of tax				65.3	6.7	72.0
Income from discontinued operations, net of tax				—	1.5	1.5
Net income attributable to Alliant Energy common shareowners				65.3	8.2	73.5

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IPL—Certain financial information relating to IPL's business segments is as follows. Intersegment revenues were not material to IPL's operations.

	Electric	Gas	Other	Total
		(in millions)		
Three Months Ended March 31, 2012				
Operating revenues	**$ 293.1**	**$ 92.8**	**$ 12.8**	**$ 398.7**
Operating income	**6.7**	**14.2**	**3.0**	**23.9**
Earnings loss for common stock				**(4.7)**
Three Months Ended March 31, 2011				
Operating revenues	330.2	131.9	15.4	477.5
Operating income	27.9	15.8	3.4	47.1
Earnings available for common stock				21.7

WPL—Certain financial information relating to WPL's business segments is as follows. Intersegment revenues were not material to WPL's operations.

	Electric	Gas	Other	Total
		(in millions)		
Three Months Ended March 31, 2012				
Operating revenues	**$ 279.3**	**$ 74.3**	**$ 0.9**	**$ 354.5**
Operating income (loss)	**52.4**	**13.5**	**(1.3)**	**64.6**
Earnings available for common stock				**31.1**
Three Months Ended March 31, 2011				
Operating revenues	290.1	97.1	1.3	388.5
Operating income (loss)	61.4	20.1	(6.7)	74.8
Earnings available for common stock				43.6

(13) DISCONTINUED OPERATIONS AND ASSETS AND LIABILIITES HELD FOR SALE

Alliant Energy is currently pursuing the disposal of its RMT business in order to narrow its strategic focus and risk profile. RMT was included in Alliant Energy's "Non-regulated—RMT" segment. Alliant Energy currently expects to complete the disposal of RMT in 2012. The RMT business qualified as assets and liabilities held for sale as of March 31, 2012. In March 2011, Alliant Energy sold its Industrial Energy Applications, Inc. (IEA) business to narrow its strategic focus and risk profile and received net proceeds of $5 million. IEA was included in Alliant Energy's "Other Non-regulated, Parent and Other" segment.

The operating results of RMT and IEA have been separately classified and reported as discontinued operations in Alliant Energy's Condensed Consolidated Statements of Income. A summary of the components of discontinued operations in Alliant Energy's Condensed Consolidated Statements of Income for the three months ended March 31 was as follows (in millions):

	2012	2011
Operating revenues	**$ 54.6**	$ 68.9
Operating expenses	**61.9**	67.9
Gain on sale of IEA	**—**	(2.5)
Interest expense and other	**—**	0.1
Income (loss) before income taxes	**(7.3)**	3.4
Income tax expense (benefit)	**(2.9)**	1.9
Income (loss) from discontinued operations, net of tax	**($ 4.4)**	$ 1.5

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A summary of the assets and liabilities held for sale on Alliant Energy's Condensed Consolidated Balance Sheets was as follows (in millions):

	March 31, 2012	Dec. 31, 2011
Assets held for sale:		
Property, plant and equipment, net	**$ 3.3**	$ 3.8
Current assets	**63.2**	115.5
Other assets	**0.3**	0.3
Total assets held for sale	**66.8**	119.6
Liabilities held for sale:		
Current liabilities	**59.1**	62.0
Other long-term liabilities and deferred credits	**—**	0.1
Total liabilities held for sale	**59.1**	62.1
Net assets held for sale	**$ 7.7**	$ 57.5

A summary of the components of cash flows for discontinued operations for the three months ended March 31 was as follows (in millions):

	2012	2011
Net cash flows from (used for) operating activities	**$ 41.1**	($ 12.5)
Net cash flows from (used for) financing activities	**(41.0)**	4.4

(14) ASSET RETIREMENT OBLIGATIONS (AROs)

A reconciliation of the changes in AROs associated with long-lived assets is as follows (in millions):

	Alliant Energy		IPL		WPL	
	2012	2011	**2012**	2011	**2012**	2011
Balance, Jan. 1	**$ 91.1**	$ 75.9	**$ 56.2**	$ 43.6	**$ 34.9**	$ 32.3
Revisions in estimated cash flows (a)	**(8.2)**	(0.3)	**(8.2)**	—	**—**	(0.3)
Liabilities settled	**(1.0)**	(0.1)	**(0.9)**	(0.1)	**(0.1)**	—
Accretion expense	**0.9**	1.1	**0.5**	0.7	**0.4**	0.4
Balance, March 31	**$ 82.8**	$ 76.6	**$ 47.6**	$ 44.2	**$ 35.2**	$ 32.4

(a) In the first quarter of 2012, IPL recorded revisions in estimated cash flows of $8.2 million based on revised remediation timing and cost information for asbestos remediation at its Sixth Street Generating Station.

(15) VARIABLE INTEREST ENTITIES (VIEs)

After making an ongoing exhaustive effort, Alliant Energy and WPL concluded they were unable to obtain the information necessary from the counterparty (a subsidiary of Calpine Corporation) for the Riverside PPA for Alliant Energy and WPL to determine whether the counterparty is a VIE and if WPL is the primary beneficiary. This PPA is currently accounted for as an operating lease. The counterparty for the Riverside PPA sells a portion of its generating capacity to WPL and can sell its energy output to WPL. Alliant Energy's and WPL's maximum exposure to loss from this PPA is undeterminable due to the inability to obtain the necessary information to complete such evaluation. Alliant Energy's (primarily WPL's) costs, excluding fuel costs, related to the Riverside PPA were $6.3 million and $6.4 million for the three months ended March 31, 2012 and 2011, respectively.

In April 2012, the PSCW approved WPL's Certificate of Authority (CA) application to acquire Riverside for approximately $393 million by the end of 2012. WPL's purchase of Riverside would replace the 490 MW of electricity output currently obtained from the Riverside PPA to meet the demand of its customers. WPL currently plans to complete the acquisition in December 2012.

(16) RELATED PARTIES

System Coordination and Operating Agreement—IPL and WPL are parties to a system coordination and operating agreement whereby Corporate Services serves as agent on behalf of IPL and WPL. The agreement, which has been approved or reviewed by FERC and all state regulatory bodies having jurisdiction, provides a contractual basis for coordinated planning, construction, operation and maintenance of the interconnected electric generation systems of IPL and WPL. As agent of the agreement, Corporate Services enters into energy, capacity, ancillary services, and transmission sale and purchase transactions. Corporate Services allocates such sales and purchases among IPL and WPL based on procedures included in the agreement. The sales credited to and purchases billed to IPL and WPL for the three months ended March 31 were as follows (in millions):

	IPL		WPL	
	2012	2011	**2012**	2011
Sales credited	**$ 2**	$ 8	**$ 2**	$ 6
Purchases billed	**72**	67	**24**	22

Service Agreement—Pursuant to a service agreement, IPL and WPL receive various administrative and general services from an affiliate, Corporate Services. These services are billed to IPL and WPL at cost based on expenses incurred by Corporate Services for the benefit of IPL and WPL, respectively. These costs consisted primarily of employee compensation, benefits and fees associated with various professional services. The amounts billed to IPL and WPL for the three months ended March 31 were as follows (in millions):

	IPL		WPL	
	2012	2011	**2012**	2011
Corporate Services billings	**$ 29**	$ 50	**$ 23**	$ 39

Net intercompany payables to Corporate Services were as follows (in millions):

	IPL		WPL	
	March 31, 2012	Dec. 31, 2011	**March 31, 2012**	Dec. 31, 2011
Net payables to Corporate Services	**$ 72**	$ 82	**$ 47**	$ 48

ATC—Pursuant to various agreements, WPL receives a range of transmission services from ATC. WPL provides operation, maintenance, and construction services to ATC. WPL and ATC also bill each other for use of shared facilities owned by each party. The related amounts billed between the parties for the three months ended March 31 were as follows (in millions):

	2012	2011
ATC billings to WPL	**$ 22**	$ 22
WPL billings to ATC	**2**	3

As of March 31, 2012 and Dec. 31, 2011, WPL owed ATC net amounts of $7 million and $6 million, respectively.

(17) EARNINGS PER SHARE

A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per weighted average common share (EPS) calculation for the three months ended March 31 was as follows (in thousands):

	2012	2011
Weighted average common shares outstanding:		
Basic EPS calculation	**110,716**	110,569
Effect of dilutive share-based awards	**25**	63
Diluted EPS calculation	**110,741**	110,632

For the three months ended March 31, 2012 and 2011, there were no potentially dilutive securities excluded from the calculation of diluted EPS.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MDA)

This MDA includes information relating to Alliant Energy, IPL and WPL, as well as Resources and Corporate Services. Where appropriate, information relating to a specific entity has been segregated and labeled as such. The following discussion and analysis should be read in conjunction with the Condensed Consolidated Financial Statements and Combined Notes to Condensed Consolidated Financial Statements included in this report as well as the financial statements, notes and MDA included in the 2011 Form 10-K. Unless otherwise noted, all "per share" references in MDA refer to earnings per diluted share.

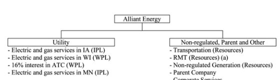
CONTENTS OF MDA

Alliant Energy's, IPL's and WPL's MDA consists of the following information:

EXECUTIVE SUMMARY

Description of Business

General—Alliant Energy is an investor-owned public utility holding company whose primary subsidiaries are IPL, WPL, Resources and Corporate Services. IPL is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas in selective markets in Iowa and southern Minnesota. WPL is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas in selective markets in southern and central Wisconsin. WPL also owns an approximate 16% interest in ATC, a transmission-only utility operating in Wisconsin, Michigan, Illinois and Minnesota. Resources is the parent company for Alliant Energy's non-regulated businesses. Corporate Services provides administrative services to Alliant Energy and its subsidiaries. An illustration of Alliant Energy's primary businesses is shown below.



(a) In 2012, Alliant Energy announced plans to sell RMT in 2012. As of March 31, 2012, Alliant Energy's RMT business qualified as assets and liabilities held for sale. The operating results of RMT have been separately classified and reported as discontinued operations in Alliant Energy's Condensed Consolidated Statements of Income.

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Financial Results

Alliant Energy's net income and EPS attributable to Alliant Energy common shareowners for the first quarter were as follows (dollars in millions, except per share amounts):

	2012		2011	
	Income (Loss)	**EPS**	Income	EPS
Continuing operations:				
Utility	**$ 26.4**	**$ 0.24**	$ 65.3	$ 0.59
Non-regulated and parent	**12.9**	**0.12**	6.7	0.06
Income from continuing operations	**39.3**	**0.36**	72.0	0.65
Income (loss) from discontinued operations	**(4.4)**	**(0.04)**	1.5	0.01
Net income	**$ 34.9**	**$ 0.32**	$ 73.5	$ 0.66

The table above includes utility, and non-regulated and parent earnings per share from continuing operations, which are non-GAAP financial measures. Alliant Energy believes utility, and non-regulated and parent earnings per share from continuing operations are useful to investors because they facilitate an understanding of segment performance and trends and provide additional information about Alliant Energy's operations on a basis consistent with the measures that management uses to manage its operations and evaluate its performance. Alliant Energy's management also uses utility earnings per share from continuing operations to determine incentive compensation.

Utility—Lower income from continuing operations in the first quarter of 2012 compared to the same period in 2011 was primarily due to:

- an estimated $0.16 per share decrease in revenues from lower sales in the first quarter of 2012 compared to the first quarter of 2011 due to weather conditions;
- $0.14 per share related to the impact of state income tax charges in the first quarter of 2012 due to changes in state apportionment projections caused by Alliant Energy's planned sale of the RMT business; and
- $0.11 per share related to the impact of IPL's tax benefit rider in the first quarter of 2012 compared to the first quarter of 2011, which is not expected to impact the full year results.

These items were partially offset by:

- $0.03 per share impact from an impairment of WPL's wind site in Wisconsin in the first quarter of 2011.

Non-regulated and parent—Higher income from continuing operations in the first quarter of 2012 compared to the same period in 2011 was primarily due to $0.04 per share of higher income tax benefits at the parent company due to the impact of IPL's tax benefit rider.

Refer to "Alliant Energy's Results of Operations," "IPL's Results of Operations" and "WPL's Results of Operations" for additional details regarding the various factors impacting their respective earnings during the first quarters of 2012 and 2011.

Strategic Overview

Alliant Energy's, IPL's and WPL's strategic plans focus on their core business of delivering regulated electric and natural gas service in Iowa, Wisconsin, and Minnesota. The strategic plans are built upon three key elements: competitive costs, safe and reliable service and balanced generation. The strategic plans for Alliant Energy, IPL and WPL include purchasing and/or constructing natural gas-fired electric generating facilities, implementing emission controls and performance upgrades at their more-efficient coal-fired electric generating facilities, constructing a new wind generating facility, and fuel switching at, and retirement of, certain older and less-efficient coal-fired generating facilities. Key strategic plan developments impacting Alliant Energy, IPL and WPL during 2012 include:

- March 2012—The Midwest Independent Transmission System Operator (MISO) indicated that the retirement of WPL's Nelson Dewey Units 1 and 2 may result in reliability issues and that transmission upgrades are necessary to enable the retirement. Under the current MISO tariff, the specific timing for the retirement of Nelson Dewey Units 1 and 2 could depend on the timing of the required transmission upgrades and various operational, market and other factors.
- April 2012—The PSCW approved WPL's CA application to acquire Riverside for approximately $393 million by the end of 2012. Subject to receiving all remaining regulatory approvals, WPL currently plans to complete the acquisition in December 2012.
- April 2012—IPL and MidAmerican each filed an updated Emissions Plan and Budget (EPB) with the IUB. IPL's EPB includes emission control projects for Ottumwa Unit 1 and Lansing Unit 4. MidAmerican's EPB includes emission control projects for George Neal Units 3 and 4. Alliant Energy and IPL currently expect the IUB to issue their decisions on IPL's and MidAmerican's EPBs by the end of 2012.

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Refer to "Strategic Overview" for additional details regarding strategic plan developments.

Rate Matters

Alliant Energy's utility subsidiaries, IPL and WPL, are subject to federal regulation by FERC, which has jurisdiction over wholesale electric rates, and state regulation in Iowa, Wisconsin and Minnesota for retail utility rates. Key regulatory developments impacting Alliant Energy, IPL and WPL during 2012 include:

- May 2012—After discussion with PSCW staff and major intervener groups, WPL filed a retail base rate filing based on a forward-looking test period that includes 2013 and 2014. The filing requests approval for WPL to implement a decrease in annual retail natural gas base rates of $13 million effective Jan. 1, 2013 followed by a freeze of such natural gas base rates through the end of 2014. The filing also requests authority to maintain customer base rates for WPL's retail electric customers at their current levels through the end of 2014. Recovery of the costs for the planned acquisition of Riverside and emission control projects at Edgewater Unit 5 and Columbia Units 1 and 2 are included in the request. The recovery of the costs for these capital projects are offset by decreases in rate base resulting from increased net deferred tax liabilities, the impact of amortizations of regulatory assets and regulatory liabilities, and the reduction of capacity payments. WPL's May 2012 retail base rate filing included a return on common equity of 10.4% and the following related provisions: (1) WPL may request a change in retail base rates if its annual return on common equity falls below 8.5%; and (2) WPL must defer a portion of its earnings if its annual return on common equity exceeds 10.65%. The amount of earnings WPL must defer is equal to 50% of its excess earnings between 10.66% and 11.40% and 100% of any excess earnings above 11.40%.

Refer to "Rate Matters" for additional details regarding regulatory developments.

Environmental Matters

Alliant Energy, IPL and WPL are subject to regulation of environmental matters by various federal, state and local authorities. Key environmental developments during 2012 that may impact Alliant Energy, IPL and WPL include:

- March 2012—FERC extended the deadline to install an agency-approved fish passage device at WPL's Prairie du Sac hydro plant to July 1, 2015.
- April 2012—The EPA published proposed NSPS for GHG, including CO2 emissions from new fossil-fueled EGUs larger than 25 MW with an output-based standard of 1,000 pounds of CO2 per MWh. This emissions rate limitation is expected to be effective upon the EPA's issuance of the final rule in the second quarter of 2013.

Refer to "Environmental Matters" for additional details regarding environmental developments.

Liquidity and Capital Resources

Based on their current liquidity positions and capital structures, Alliant Energy, IPL and WPL believe they will be able to secure the additional capital required to implement their strategic plans and to meet their long-term contractual obligations. Key financing developments impacting Alliant Energy, IPL and WPL during 2012 include:

- March 2012—FERC authorized Corporate Services to issue up to $150 million in long-term debt securities and to maintain up to $200 million in short-term debt securities outstanding (including borrowings from its parent or other affiliates) during the period from March 31, 2012 through March 30, 2014.
- March 2012—IPL extended through March 2014 the purchase commitment from the third-party financial institution to which it sells its receivables.
- March 2012—At March 31, 2012, Alliant Energy and its subsidiaries had $918 million of available capacity under their revolving credit facilities, $35 million of available capacity at IPL under its sales of accounts receivable program and $31 million of cash and cash equivalents.
- April 2012—Alliant Energy exercised its option under the corporate headquarters lease and purchased the building at the expiration of the lease term for $49 million.

Refer to "Liquidity and Capital Resources" for additional details regarding financing developments.

STRATEGIC OVERVIEW

A summary of Alliant Energy's, IPL's and WPL's strategic overview is included in the 2011 Form 10-K and has not changed materially from the items reported in the 2011 Form 10-K, except as described below.

Potential Natural Gas-Fired Generation Projects -

IPL's Potential Construction of a Natural Gas-Fired Electric Generating Facility—IPL received numerous proposals in response to the RFP issued in January 2012 seeking firm long-term supplies of non-intermittent capacity and energy delivered to IPL's control area. The RFP solicited ownership and/or long-term PPA proposals for either new or existing resources or access to a portion of the output of a portfolio of system resources. IPL is currently evaluating the proposals from the RFP as part of the due diligence process for the potential construction of a new 600 MW natural gas-fired combined-cycle generating facility and expects to make a decision regarding its plans to meet the future demands of its customers in the third quarter of 2012.

WPL's Potential Purchase of a Natural Gas-Fired Electric Generating Facility—In April 2012, the PSCW approved WPL's CA application to acquire Riverside, a 600 MW natural gas-fired electric generating facility in Beloit, Wisconsin, for approximately $393 million by the end of 2012. WPL's purchase of Riverside would replace the 490 MW of electricity output currently obtained from the Riverside PPA to meet the demand of its customers. Subject to receiving all remaining regulatory approvals including FERC and under the Hart—Scott—Rodino Act, WPL currently plans to complete the acquisition in December 2012.

Coal-Fired Generation Project -

WPL's Nelson Dewey Generating Station—Nelson Dewey is a 208 MW electric generating facility located in Cassville, Wisconsin that includes two units (Unit 1 and Unit 2), which are configured to burn coal. In 2011, WPL filed documents with MISO to evaluate any system reliability implications of the eventual full retirement of Nelson Dewey. In March 2012, MISO indicated that the retirement of both units may result in reliability issues and that transmission upgrades are necessary to enable the retirement. Under the current MISO tariff, the specific timing for the retirement of Nelson Dewey Units 1 and 2 could depend on the timing of the required transmission upgrades and various operational, market and other factors.

Environmental Compliance Plans -

IPL's Emission Control Projects—In April 2012, IPL and MidAmerican each filed an updated EPB with the IUB. IPL's EPB includes emission control projects for Ottumwa Unit 1 and Lansing Unit 4. MidAmerican's EPB includes emission control projects for George Neal Units 3 and 4. Alliant Energy and IPL currently expect the IUB to issue their decisions on IPL's and MidAmerican's EPBs by the end of 2012.

RATE MATTERS

A summary of Alliant Energy's, IPL's and WPL's rate matters is included in the 2011 Form 10-K and has not changed materially from the items reported in the 2011 Form 10-K, except as described below.

Recent Retail Base Rate Filings—Details of IPL's and WPL's recent retail base rate cases impacting their historical and future results of operations are as follows (dollars in millions; Electric (E); Gas (G); Not Applicable (N/A)):

Retail Base Rate Cases	Utility Type	Filing Date	Interim Increase Implemented (a)(b)	Interim Effective Date	Final Increase Granted (b)	Actual/ Expected Final Effective Date
WPL:						
Wisconsin 2013/2014 Test Period	E/G	May-12	N/A	N/A	TBD	Jan-13
IPL:						
Minnesota 2009 Test Year	E	May-10	$ 14	Jul-10	$ 8	Feb-12 (c)
Iowa 2009 Test Year	E	Mar-10	119	Mar-10	114	Apr-11

(a) In Iowa, IPL's interim rates can be implemented 10 days after the filing date, without regulatory review and are subject to refund, pending determination of final rates. In Minnesota, IPL's interim rates can be implemented 60 days after the filing date, with regulatory review and subject to refund, pending determination of final rates. The amount of the interim rates is replaced by the amount of final rates once the final rates are granted.

(b) Base rate increases reflect both returns on additions to IPL's infrastructure and recovery of changes in costs incurred or expected to be incurred by IPL. Given a portion of the rate increases will offset changes in costs, revenues from rate increases should not be expected to result in an equal increase in income.

(c) The final recovery amount for the Minnesota retail portion of IPL's Whispering Willow—East wind project construction costs will be addressed in a separate proceeding that is currently expected to be completed in 2012.

Wisconsin Retail Electric and Gas Rate Case (2013/2014 Test Period)—In May 2012, after discussions with PSCW staff and major intervener groups, WPL filed a retail base rate filing based on a forward-looking test period that includes 2013 and 2014. The filing requests approval for WPL to implement a decrease in annual retail natural gas base rates of $13 million effective Jan. 1, 2013 followed by a freeze of such natural gas base rates through the end of 2014. The filing also requests authority to maintain customer base rates for WPL's retail electric customers at their current levels through the end of 2014.

Recovery of the costs for the planned acquisition of Riverside, the SCR project at Edgewater Unit 5 and the scrubber and baghouse projects at Columbia Units 1 and 2 are included in the request. The recovery of the costs for these capital projects are offset by decreases in rate base resulting from increased net deferred tax liabilities, the impact of amortizations of regulatory assets and regulatory liabilities, and the reduction of capacity payments. WPL's May 2012 retail base rate filing included a return on common equity of 10.4% and the following related provisions: (1) WPL may request a change in retail base rates if its annual return on common equity falls below 8.5%; and (2) WPL must defer a portion of its earnings if its annual return on common equity exceeds 10.65%. The amount of earnings WPL must defer is equal to 50% of its excess earnings between 10.66% and 11.40% and 100% of any excess earnings above 11.40%. In addition, the filing requests WPL maintain its ability to request deferrals based on current practices. The retail base rate filing in May 2012 also included the following key assumptions (Common Equity (CE); Preferred Equity (PE); Long-term Debt (LD); Short-term Debt (SD); Weighted-average Cost of Capital (WACC); dollars in billions):

		Regulatory Capital Structure					
Utility Type	Test Period	CE	PE	LD	SD	After-tax WACC	Average Rate Base
Electric	2013	49.3%	2.0%	45.5%	3.2%	7.8%	$ 2.1
Electric	2014	49.4%	1.9%	44.2%	4.5%	7.8%	2.2
Gas	2013	49.3%	2.0%	45.5%	3.2%	7.8%	0.2
Gas	2014	49.4%	1.9%	44.2%	4.5%	7.8%	0.2

The fuel-related cost component of WPL's retail electric rates for 2013 and 2014 will be addressed in separate filings. WPL currently expects to make retail fuel-related cost filings for 2013 and 2014 in the second or third quarters of 2012 and 2013, respectively.

IPL's Minnesota Retail Electric Rate Case (2009 Test Year)—In May 2010, IPL filed a request with the Minnesota Public Utilities Commission (MPUC) to increase annual rates for its Minnesota retail electric customers. In conjunction with the filing, IPL implemented an interim retail rate increase of $14 million, on an annual basis, effective July 6, 2010. The interim retail rate increase was approved by the MPUC, subject to refund pending determination of final rates from the request. In November 2011, IPL received an order from the MPUC establishing a final annual retail electric rate increase equivalent to $11 million. The final annual retail electric rate increase of $11 million includes $8 million of higher base rates, $2 million from the temporary renewable energy rider and $1 million from the utilization of regulatory liabilities to offset higher electric transmission service costs. Because the final rate increase level was below the interim retail rate increase level implemented in July 2010, IPL began refunding a portion of the interim rates collected to its Minnesota retail electric customers in the first quarter of 2012. As of March 31, 2012, Alliant Energy and IPL reserved $3 million, including interest, for remaining refunds anticipated to be paid to IPL's Minnesota retail electric customers in 2012.

IPL's Iowa Retail Electric Rate Case (2009 Test Year)—In March 2010, IPL filed a request with the IUB to increase annual rates for its Iowa retail electric customers. In conjunction with the filing, IPL implemented an interim retail electric rate increase of $119 million, or approximately 10%, on an annual basis, effective March 20, 2010, without regulatory review and subject to refund pending determination of final rates. In February 2011, IPL received an order from the IUB authorizing a final annual retail electric rate increase of $114 million, or approximately 10%. Because the final rate increase level was below the interim rate increase level implemented in March 2010, IPL refunded to its Iowa retail customers $5 million in 2011.

Tax Benefit Rider—In January 2011, the IUB approved a tax benefit rider proposed by IPL in its Iowa retail electric rate case (2009 Test Year). The tax benefit rider, which was implemented in late February 2011, utilizes regulatory liabilities to credit bills of Iowa retail customers to help offset the impact of recent rate increases on such customers. These credits on customers' electric bills reduce electric revenues each quarter based on customers' kilowatt-hour usage, which is fairly consistent throughout each calendar year. The tax benefit rider also results in a reduction in income tax expense from the benefits of the tax initiatives. While the tax benefit rider is not expected to impact total year earnings, it does result in considerable quarterly variations in earnings due to the accounting rules for recording income taxes in interim financial statements. According to these rules, the offsetting tax benefits from the tax benefit rider are recorded based on the percentage of annual expected earnings each quarter, which fluctuates significantly causing considerable quarterly variation in the income tax benefits from the tax benefit rider. In the first quarters of 2012 and 2011, the quarterly variation in earnings from the tax benefit rider resulted in a net increase (decrease) in Alliant Energy's earnings of ($3) million ($6 million at Alliant Energy's parent company and ($9) million at IPL) and $5 million ($2 million at Alliant Energy's parent company and $3 million at IPL), respectively. As stated previously, the quarterly variations in earnings from the tax benefit rider will offset each other for each calendar year resulting in no earnings impact for the full calendar years of 2012 and 2011.

As of March 31, 2012, Alliant Energy's and IPL's remaining regulatory liabilities related to the tax benefit rider recognized were $329 million. The final amount of regulatory liabilities returned to customers under the tax benefit rider is dependent on the amount of tax benefits sustained under IRS audit and therefore is subject to change. Refer to Note 4 of the "Combined Notes to Condensed Consolidated Financial Statements" and "Results of Operations—Income Taxes" for additional discussion of the impact of the tax benefit rider on Alliant Energy's and IPL's income tax expense and effective income tax rates.

Planned Utility Rate Case in 2012 -

Iowa Retail Gas Rate Case (2011 Test Year)—IPL currently expects to file an Iowa retail gas rate case in the second quarter of 2012 based on a 2011 historical test period. The key drivers for the anticipated filing include recovery of increased costs and capital investments since IPL's last Iowa gas retail rate case filed in 2005. Any rate changes are expected to be implemented in two phases with interim rates effective approximately 10 days after the filing and final rates effective approximately 11 months after the filing date. IPL currently expects to propose a tax benefit rider that will utilize regulatory liabilities generated from tax initiatives to credit bills of Iowa retail gas customers to partially offset any requested rate increase from this case.

WPL's Retail Fuel-related Rate Filing -

2012 Test Year—In December 2011, WPL received an order from the PSCW authorizing an annual retail electric rate increase of $4 million related to expected changes in retail electric production fuel and energy purchases (fuel-related costs). The December 2011 order also required WPL to defer direct CSAPR compliance costs that are not included in the fuel monitoring level and set a zero percent tolerance band for the CSAPR-related deferral. The 2012 fuel costs, excluding deferred CSAPR compliance costs, will be monitored using an annual bandwidth of plus or minus 2%. The rate change granted from this request was effective Jan. 1, 2012.

ENVIRONMENTAL MATTERS

A summary of Alliant Energy's, IPL's and WPL's environmental matters is included in the 2011 Form 10-K and has not changed materially from the items reported in the 2011 Form 10-K, except as described below.

Air Quality -

Air Permitting Violation Claims—Refer to Note 11(b) of the "Combined Notes to Condensed Consolidated Financial Statements" for discussion of complaints filed by the Sierra Club in 2010 and an NOV issued by the EPA in 2009 regarding alleged air permitting violations at Nelson Dewey, Columbia and Edgewater.

Water Quality -

Hydroelectric Fish Passages Device—In March 2012, FERC extended the deadline to install an agency-approved fish passage device at WPL's Prairie du Sac hydro plant to July 1, 2015. Alliant Energy and WPL believe the required capital investments and/or modifications to install the fish passage device at the facility could be significant.

Land and Solid Waste -

MGP Sites—Refer to Note 11(d) of the "Combined Notes to Condensed Consolidated Financial Statements" for discussion of IPL's and WPL's MGP sites.

GHG Emissions -

EPA NSPS for GHG Emissions from Electric Utilities—In April 2012, the EPA published proposed NSPS for GHG, including CO_2 emissions from new fossil-fueled EGUs larger than 25 MW with an output-based emissions rate limitation of 1,000 pounds of CO_2 per MWh. This emissions rate limitation is expected to be effective upon the EPA's issuance of the final rule in the second quarter of 2013. The proposed NSPS for new EGUs is expected to apply to IPL's potential construction of a new 600 MW natural gas-fired combined-cycle electric generating facility in Iowa, which will be designed to achieve compliance with the proposed CO_2 emissions rate limitation. The EPA announced the issuance of proposed regulations for existing EGUs will be delayed and has not yet established a new schedule. Alliant Energy, IPL and WPL are currently unable to predict with certainty the final outcome of this proposed standard, but expect that expenditures to comply with any regulations to reduce GHG emissions could be significant.

LEGISLATIVE MATTERS

A summary of Alliant Energy's, IPL's and WPL's legislative matters is included in the 2011 Form 10-K and has not changed materially from the items reported in the 2011 Form 10-K, except as described below.

Federal Tax Legislation -

Small Business Jobs Act of 2010 (SBJA) and the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (the Act)—In 2010, the SBJA and the Act were enacted. The most significant provisions of the SBJA and the Act for Alliant Energy, IPL and WPL were provisions related to the extension of bonus depreciation deductions for certain expenditures for property that are incurred through Dec. 31, 2012. Refer to Note 4 of the "Combined Notes to Condensed Consolidated Financial Statements" for further discussion of the SBJA and the Act, including estimated bonus depreciation deductions expected to be claimed on Alliant Energy's 2012 U.S. federal income tax return.

ALLIANT ENERGY'S RESULTS OF OPERATIONS

Overview—First Quarter Results—Refer to "Executive Summary" for an overview of Alliant Energy's first quarter 2012 and 2011 earnings and the various components of Alliant Energy's business. Additional details of Alliant Energy's earnings for the first quarters of 2012 and 2011 are discussed below.

Utility Electric Margins—Electric margins are defined as electric operating revenues less electric production fuel, energy purchases and purchased electric capacity expenses. Management believes that electric margins provide a more meaningful basis for evaluating utility operations than electric operating revenues since electric production fuel, energy purchases and purchased electric capacity expenses are generally passed through to customers, and therefore, result in changes to electric operating revenues that are comparable to changes in electric production fuel, energy purchases and purchased electric capacity expenses. Electric margins and MWh sales for Alliant Energy for the first quarter were as follows:

	Revenues and Costs (dollars in millions)			MWhs Sold (MWhs in thousands)		
	2012	2011	Change	**2012**	2011	Change
Residential	**$ 218.2**	$ 240.4	(9%)	**1,863**	2,024	(8%)
Commercial	**132.9**	142.7	(7%)	**1,515**	1,533	(1%)
Industrial	**164.0**	169.6	(3%)	**2,815**	2,712	4%
Retail subtotal	**515.1**	552.7	(7%)	**6,193**	6,269	(1%)
Sales for resale:						
Wholesale	**43.3**	46.0	(6%)	**757**	843	(10%)
Bulk power and other	**2.8**	11.7	(76%)	**85**	472	(82%)
Other	**11.2**	9.9	13%	**37**	38	(3%)
Total revenues/sales	**572.4**	620.3	(8%)	**7,072**	7,622	(7%)
Electric production fuel expense	**70.9**	110.1	(36%)			
Energy purchases expense	**89.0**	83.9	6%			
Purchased electric capacity expense	**61.5**	57.8	6%			
Margins	**$ 351.0**	$ 368.5	(5%)			

First Quarter 2012 vs. First Quarter 2011 Summary—Electric margins decreased $18 million, or 5%, primarily due to an estimated $16 million decrease in electric margins from changes in sales caused by weather conditions in Alliant Energy's service territories and $13 million of decreased revenues due to higher credits on Iowa retail electric customers' bills resulting from the tax benefit rider in the first quarter of 2012 compared to the same period in 2011. Other decreases to electric margins included $2 million of higher purchased electric capacity expenses at WPL related to the Kewaunee PPA and $2 million of lower energy conservation revenues at IPL. Estimated increases (decreases) to Alliant Energy's electric margins from the impacts of weather during the first quarters of 2012 and 2011 were ($12) million and $4 million, respectively. IPL's tax benefit rider is expected to result in reductions in electric revenues that are offset by reductions in income tax expense for the year ended Dec. 31, 2012. Changes in energy conservation revenues were largely offset by changes in energy conservation expenses included in other operation and maintenance expenses. These items were partially offset by $6 million of higher revenues at IPL related to changes in recovery mechanisms for transmission costs due to the transmission rider implemented in the first quarter of 2011, a $5 million increase in electric margins from changes in the recovery of electric production fuel and energy purchases expenses at WPL and an increase in weather-normalized sales volumes at both IPL and WPL. The higher transmission rider revenues were offset by higher electric transmission service expenses.

Weather Conditions—Temperatures during the first quarter of 2012 were 20% to 25% warmer than normal, as measured by heating degree days (HDD) in Alliant Energy's service territories. These warmer temperatures caused a significant decrease in IPL's and WPL's electric and gas sales due to the lack of demand by customers for heating. Cooling degree days (CDD) were also calculated in Alliant Energy's service territories in the first quarter of 2012. These CDD caused a modest increase in electric sales related to demand by customers for air conditioning usage. HDD and CDD in Alliant Energy's service territories for the first quarter were as follows:

	Actual		
	2012	**2011**	**Normal**
HDD (a):			
Cedar Rapids, Iowa (IPL)	**2,692**	3,590	3,425
Madison, Wisconsin (WPL)	**2,717**	3,676	3,511

	Actual		
	2012	**2011**	**Normal**
CDD (a):			
Cedar Rapids, Iowa (IPL)	**28**	—	1
Madison, Wisconsin (WPL)	**26**	—	—

(a) HDD and CDD are calculated using a simple average of the high and low temperatures each day compared to a 65-degree base. Normal degree days are calculated using a rolling 20-year average of historical HDD and CDD.

Electric Production Fuel and Energy Purchases (Fuel-related) Cost Recoveries—Alliant Energy burns coal and other fossil fuels to produce electricity at its generating facilities. The cost of fossil fuels used during each period is included in electric production fuel expense. Alliant Energy also purchases electricity to meet the demand of its customers and charges these costs to energy purchases expense. Alliant Energy's electric production fuel expense decreased $39 million, or 36%, in the first quarter of 2012. The decrease was primarily due to lower MISO dispatch of Alliant Energy's generating facilities in the first quarter of 2012, which resulted in lower fuel consumption. Alliant Energy's energy purchases expense increased $5 million, or 6%, in the first quarter of 2012. The increase was primarily due to higher energy volumes purchased resulting from the lower MISO dispatch of Alliant Energy's generating facilities in the first quarter of 2012, largely offset by lower energy prices. The impact of changes in electricity volumes generated from Alliant Energy's generating facilities was largely offset by the impact of the changes in energy volumes purchased and changes in bulk power sales volumes discussed below.

Due to IPL's rate recovery mechanisms for fuel-related costs, changes in fuel-related costs resulted in comparable changes in electric revenues and, therefore, did not have a significant impact on IPL's electric margins. WPL's rate recovery mechanism for wholesale fuel-related costs also provides for adjustments to its wholesale electric rates for changes in commodity costs, thereby mitigating impacts of changes to commodity costs on its electric margins.

WPL's retail fuel-related costs incurred during the first quarter of 2012 were lower than the forecasted fuel-related costs used to set retail rates during such period. WPL estimates the lower than forecasted retail fuel-related costs increased electric margins by approximately $1 million during the first quarter of 2012. WPL's retail fuel-related costs incurred during the first quarter of 2011 were higher than the forecasted fuel-related costs used to set retail rates during such period. WPL estimates the higher than forecasted retail fuel-related costs decreased electric margins by approximately $4 million during the first quarter of 2011.

Purchased Electric Capacity Expenses—Alliant Energy enters into PPAs to help meet the electricity demand of IPL's and WPL's customers. Certain of these PPAs include minimum payments for IPL's and WPL's rights to electric generating capacity. Details of purchased electric capacity expense included in the utility electric margins table above for the first quarter were as follows (in millions):

	2012	**2011**
DAEC PPA (IPL)	**$ 40**	$ 39
Kewaunee PPA (WPL)	**15**	13
Riverside PPA (WPL)	**6**	6
Other	**1**	—
	$ 62	$ 58

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Sales Trends—Retail sales volumes decreased 1% in the first quarter of 2012 compared to the same period in 2011, primarily due to warmer weather conditions in Alliant Energy's service territories. This item was largely offset by higher sales to industrial customers driven by increased production requirements and an extra day of sales due to the leap year.

Wholesale sales volumes decreased 10% in the first quarter of 2012 compared to the same period in 2011, primarily due to the impact of weather conditions and changes in sales to WPL's partial-requirement wholesale customers that have contractual options to be served by WPL, other power supply sources or the MISO market.

Bulk power and other revenue changes were largely due to changes in revenues from sales in the wholesale energy markets operated by MISO and PJM Interconnection, LLC. These changes are impacted by several factors including the availability of Alliant Energy's generating facilities and electricity demand within these wholesale energy markets. Changes in bulk power and other sales revenues were offset by changes in fuel-related costs and therefore did not have a significant impact on electric margins.

Utility Gas Margins—Gas margins are defined as gas operating revenues less cost of gas sold. Management believes that gas margins provide a more meaningful basis for evaluating utility operations than gas operating revenues since cost of gas sold is generally passed through to customers, and therefore results in changes to gas operating revenues that are comparable to changes in cost of gas sold. Gas margins and Dth sales for Alliant Energy for the first quarter were as follows:

	Revenues and Costs (dollars in millions)			Dths Sold (Dths in thousands)		
	2012	2011	Change	**2012**	2011	Change
Residential	**$ 98.5**	$ 135.1	(27%)	**10,527**	14,101	(25%)
Commercial	**55.2**	76.1	(27%)	**7,103**	9,091	(22%)
Industrial	**5.9**	10.2	(42%)	**952**	1,446	(34%)
Retail subtotal	**159.6**	221.4	(28%)	**18,582**	24,638	(25%)
Transportation/other	**7.5**	7.6	(1%)	**13,120**	13,974	(6%)
Total revenues/sales	**167.1**	229.0	(27%)	**31,702**	38,612	(18%)
Cost of gas sold	**104.8**	156.4	(33%)			
Margins	**$ 62.3**	$ 72.6	(14%)			

First Quarter 2012 vs. First Quarter 2011 Summary—Gas margins decreased $10 million, or 14%, primarily due to an estimated $13 million decrease in gas margins from changes in sales caused by weather conditions in Alliant Energy's service territories. Estimated increases (decreases) to Alliant Energy's gas margins from the impacts of weather during the first quarters of 2012 and 2011 were ($10) million and $3 million, respectively.

Refer to "Utility Electric Margins" for details of Alliant Energy's HDD data. Refer to "Rate Matters" for discussion of retail rate cases.

Utility Other Revenues—Other revenues for the utilities decreased $3 million primarily due to lower coal sales at IPL during the first quarter of 2012 as compared to the first quarter of 2011. Changes in utility other revenues were largely offset by related changes in utility other operation and maintenance expenses.

Electric Transmission Service Expense—Alliant Energy's electric transmission service expense for the utilities increased $8 million primarily due to higher transmission costs at IPL related to transmission services from ITC Midwest LLC (ITC). The increase was primarily due to $2 million of higher electric transmission service costs billed by ITC to IPL in the first quarter of 2012 compared to the first quarter of 2011 due to a modest increase in transmission service rates and the impact of IPL utilizing $5 million of regulatory liabilities to credit a portion of the transmission service expenses billed to IPL by ITC during the first quarter of 2011. Alliant Energy currently estimates electric transmission service expenses related to ITC will be approximately $30 million to $35 million higher in 2012 compared to 2011. This estimate is impacted by monthly peak demands. IPL is currently recovering the Iowa retail portion of these increased electric transmission service costs from its retail electric customers in Iowa through the transmission cost rider resulting in an offsetting increase in electric revenues.

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Utility Other Operation and Maintenance Expenses—Alliant Energy's other operation and maintenance expenses for the utilities decreased $11 million due to the following reasons (amounts represent variances between the first quarter of 2012 and the first quarter of 2011 in millions):

	Alliant Energy	IPL	WPL
Wind site impairment charge at WPL in 2011 (a)	($5)	$—	($5)
Lower generation operation and maintenance expenses at IPL (b)	(2)	(2)	—
Lower energy conservation expenses at IPL (c)	(2)	(2)	—
Lower expenses related to coal sales at IPL (d)	(2)	(2)	—
Other (primarily other administrative and general expenses)	—	(4)	4
	($11)	($10)	($1)

(a) Refer to Note 1(c) of the "Combined Notes to Condensed Consolidated Financial Statements" for details of the wind site impairment charge recorded by WPL in the first quarter of 2011.
(b) Resulting from the timing of maintenance projects at IPL's electric generating facilities.
(c) Changes in energy conservation expenses at Alliant Energy and IPL are largely offset by changes in energy conservation revenues at Alliant Energy and IPL.
(d) Changes in expenses related to coal sales at IPL were largely offset by changes in coal sales revenue at IPL.

Depreciation and Amortization Expenses—Depreciation and amortization expenses increased $5 million primarily due to higher depreciation rates at IPL during the first quarter of 2012 as compared to the same period in 2011 resulting from IPL's most recent depreciation study, and property additions including the impacts of higher depreciation expense recognized in the first quarter of 2012 related to WPL's Bent Tree—Phase I wind project.

Income Taxes—Details of the effective income tax rates for Alliant Energy's continuing operations during the first quarter were as follows:

	2012	2011
Statutory federal income tax rate	**35.0%**	35.0%
State apportionment changes	**21.4**	—
IPL's tax benefit rider	**(12.2)**	(8.9)
Production tax credits	**(6.9)**	(5.7)
Other items, net	**1.7**	1.9
Overall income tax rate	**39.0%**	22.3%

Refer to Note 4 of the "Combined Notes to Condensed Consolidated Financial Statements" for additional discussion of state apportionment changes, IPL's tax benefit rider implemented in the first quarter of 2011 and production tax credits.

Income (Loss) from Discontinued Operations, Net of Tax—Refer to Note 13 of the "Combined Notes to Condensed Consolidated Financial Statements" for discussion of Alliant Energy's discontinued operations.

Preferred Dividend Requirements of Subsidiaries—Preferred dividend requirements of subsidiaries decreased $2 million due to a $2 million charge in the first quarter of 2011 related to IPL's redemption of its 7.10% Series C Cumulative Preferred Stock in 2011.

IPL'S RESULTS OF OPERATIONS

Overview—First Quarter Results—Earnings available for common stock decreased $26 million primarily due to lower electric and gas margins resulting from the impacts of weather in the first quarter of 2012 and increased credits on retail electric customers' bills in Iowa from the tax benefit rider, and tax charges in the first quarter of 2012 resulting from changes in state apportionment projections caused by Alliant Energy's planned sale of the RMT business.

Electric Margins—Electric margins are defined as electric operating revenues less electric production fuel, energy purchases and purchased electric capacity expenses. Management believes that electric margins provide a more meaningful basis for evaluating utility operations than electric operating revenues since electric production fuel, energy purchases and purchased electric capacity expenses are generally passed through to customers, and therefore, result in changes to electric operating

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revenues that are comparable to changes in electric production fuel, energy purchases and purchased electric capacity expenses. Electric margins and MWh sales for IPL for the first quarter were as follows:

	Revenues and Costs (dollars in millions)			MWhs Sold (MWhs in thousands)		
	2012	2011	Change	**2012**	2011	Change
Residential	**$ 115.6**	$ 131.9	(12%)	**1,021**	1,129	(10%)
Commercial	**75.5**	84.5	(11%)	**953**	966	(1%)
Industrial	**87.2**	95.4	(9%)	**1,759**	1,697	4%
Retail subtotal	**278.3**	311.8	(11%)	**3,733**	3,792	(2%)
Sales for resale:						
Wholesale	**6.1**	6.7	(9%)	**99**	105	(6%)
Bulk power and other	**1.4**	6.0	(77%)	**45**	189	(76%)
Other	**7.3**	5.7	28%	**20**	21	(5%)
Total revenues/sales	**293.1**	330.2	(11%)	**3,897**	4,107	(5%)
Electric production fuel expense	**32.9**	61.2	(46%)			
Energy purchases expense	**41.2**	35.6	16%			
Purchased electric capacity expense	**41.0**	39.3	4%			
Margins	**$ 178.0**	$ 194.1	(8%)			

First Quarter 2012 vs. First Quarter 2011 Summary—Electric margins decreased $16 million, or 8%, primarily due to $13 million of decreased revenues in the first quarter of 2012 due to additional credits on Iowa retail electric customers' bills resulting from the tax benefit rider and an estimated $11 million decrease in electric margins from changes in sales caused by weather conditions in IPL's service territory. Electric margins were also decreased by $2 million of lower energy conservation revenues. IPL's tax benefit rider is expected to result in reductions in electric revenues that are offset by reductions in income tax expenses for the year ended Dec. 31, 2012. Estimated increases (decreases) to IPL's electric margins from the impacts of weather during the first quarters of 2012 and 2011 were ($8) million and $3 million, respectively. Changes in energy conservation revenues were largely offset by changes in energy conservation expenses included in other operation and maintenance expenses. These items were partially offset by $6 million of higher revenues related to changes in recovery mechanisms for transmission costs due to the transmission rider and an increase in weather-normalized retail sales volumes. The higher transmission rider revenues were offset by higher electric transmission service expenses.

Refer to "Alliant Energy's Results of Operations—Utility Electric Margins" for details on IPL's HDD and CDD data, purchased electric capacity expenses, recoveries of electric production fuel and energy purchases expenses and sales trends.

Gas Margins—Gas margins are defined as gas operating revenues less cost of gas sold. Management believes that gas margins provide a more meaningful basis for evaluating utility operations than gas operating revenues since cost of gas sold is generally passed through to customers, and therefore, results in changes to gas operating revenues that are comparable to changes in cost of gas sold. Gas margins and Dth sales for IPL for the first quarter were as follows:

	Revenues and Costs (dollars in millions)			Dths Sold (Dths in thousands)		
	2012	2011	Change	**2012**	2011	Change
Residential	**$ 53.8**	$ 77.8	(31%)	**5,991**	8,255	(27%)
Commercial	**30.5**	43.4	(30%)	**4,034**	5,036	(20%)
Industrial	**4.2**	6.7	(37%)	**710**	940	(24%)
Retail subtotal	**88.5**	127.9	(31%)	**10,735**	14,231	(25%)
Transportation/other	**4.3**	4.0	8%	**7,893**	7,429	6%
Total revenues/sales	**92.8**	131.9	(30%)	**18,628**	21,660	(14%)
Cost of gas sold	**57.3**	92.6	(38%)			
Margins	**$ 35.5**	$ 39.3	(10%)			

First Quarter 2012 vs. First Quarter 2011 Summary—Gas margins decreased $4 million, or 10%, primarily due to an estimated $7 million decrease in gas margins from changes in sales caused by weather conditions in IPL's service territory. Estimated increases (decreases) to IPL's gas margins from the impacts of weather during the first quarters of 2012 and 2011 were ($5) million and $2 million, respectively.

Refer to "Alliant Energy's Results of Operations—Utility Electric Margins" for details of IPL's HDD data. Refer to "Rate Matters" for discussion of retail rate cases.

Steam and Other Revenues—Steam and other revenues decreased $3 million primarily due to lower coal sales during the first quarter of 2012 as compared to the first quarter of 2011. Changes in steam and other revenues were largely offset by related changes in other operation and maintenance expenses.

Electric Transmission Service Expense—Electric transmission service expense increased $8 million primarily due to higher transmission costs related to transmission services from ITC. The increase was primarily due to $2 million of higher electric transmission service costs billed by ITC to IPL in the first quarter of 2012 compared to the first quarter of 2011 due to a modest increase in transmission service rates and the impact of IPL utilizing $5 million of regulatory liabilities to credit a portion of the transmission service expenses billed to IPL by ITC during the first quarter of 2011. IPL currently estimates electric transmission service expenses related to ITC will be approximately $30 million to $35 million higher in 2012 compared to 2011. This estimate is impacted by monthly peak demands. IPL is currently recovering the Iowa retail portion of these increased electric transmission service costs from its retail electric customers in Iowa through the transmission cost rider resulting in an offsetting increase in electric revenues.

Other Operation and Maintenance Expenses—Other operation and maintenance expenses decreased $10 million primarily due to $2 million of lower generation operation and maintenance expenses resulting from the timing of maintenance projects, $2 million of lower energy conservation expenses, $2 million of lower expenses related to coal sales and decreases in other administrative and general expenses. Changes in energy conservation expenses were largely offset by changes in energy conservation revenues included in electric and gas margins. Changes in expenses related to coal sales were largely offset by changes in steam and other revenues.

Refer to "Alliant Energy's Results of Operations—Utility Other Operation and Maintenance Expenses" for additional details of IPL's other operation and maintenance expenses.

Depreciation and Amortization Expenses—Depreciation and amortization expenses increased $3 million primarily due to higher depreciation rates during the first quarter of 2012 as compared to the same period in 2011 resulting from IPL's most recent depreciation study and property additions.

Income Taxes—Details of IPL's effective income tax rates during the first quarter were as follows. The overall income tax rate for the first quarter of 2012 is not meaningful given the impact of IPL's low income before income taxes for such period.

	2012	2011
Statutory federal income tax rate	**35.0%**	35.0%
State apportionment changes	**137.3**	—
Tax benefit rider	**(37.5)**	(22.9)
Production tax credits	**(9.6)**	(6.5)
Other items, net	**0.2**	0.3
Overall income tax rate	**125.4%**	5.9%

Refer to Note 4 of the "Combined Notes to Condensed Consolidated Financial Statements" for additional discussion of state apportionment changes, the tax benefit rider and production tax credits.

Preferred Dividend Requirements—Preferred dividend requirements decreased $2 million due to a $2 million charge in the first quarter of 2011 related to IPL's redemption of its 7.10% Series C Cumulative Preferred Stock in 2011.

WPL'S RESULTS OF OPERATIONS

Overview—First Quarter Results—WPL's earnings available for common stock decreased $13 million primarily due to tax charges in the first quarter of 2012 resulting from changes in state apportionment projections caused by Alliant Energy's planned sale of the RMT business and lower electric and gas margins resulting from the impacts of weather in the first quarter of 2012. These items were partially offset by a $5 million wind site impairment charge recorded in the first quarter of 2011.

Electric Margins—Electric margins are defined as electric operating revenues less electric production fuel, energy purchases and purchased electric capacity expenses. Management believes that electric margins provide a more meaningful basis for evaluating utility operations than electric operating revenues since electric production fuel, energy purchases and purchased

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electric capacity expenses are generally passed through to customers, and therefore result in changes to electric operating revenues that are comparable to changes in electric production fuel, energy purchases and purchased electric capacity expenses. Electric margins and MWh sales for WPL for the first quarter were as follows:

	Revenues and Costs (dollars in millions)			MWhs Sold (MWhs in thousands)		
	2012	2011	Change	**2012**	2011	Change
Residential	**$ 102.6**	$ 108.5	(5%)	**842**	895	(6%)
Commercial	**57.4**	58.2	(1%)	**562**	567	(1%)
Industrial	**76.8**	74.2	4%	**1,056**	1,015	4%
Retail subtotal	**236.8**	240.9	(2%)	**2,460**	2,477	(1%)
Sales for resale:						
Wholesale	**37.2**	39.3	(5%)	**658**	738	(11%)
Bulk power and other	**1.4**	5.7	(75%)	**40**	283	(86%)
Other	**3.9**	4.2	(7%)	**17**	17	— %
Total revenues/sales	**279.3**	290.1	(4%)	**3,175**	3,515	(10%)
Electric production fuel expense	**38.0**	48.9	(22%)			
Energy purchases expense	**47.8**	48.3	(1%)			
Purchased electric capacity expense	**20.5**	18.5	11%			
Margins	**$ 173.0**	$ 174.4	(1%)			

First Quarter 2012 vs. First Quarter 2011 Summary—Electric margins decreased $1 million, or 1%, primarily due to an estimated $5 million decrease in electric margins from changes in sales caused by weather conditions in WPL's service territory and $2 million of higher purchased electric capacity expenses related to the Kewaunee PPA. Estimated increases (decreases) to WPL's electric margins from the impacts of weather during the first quarters of 2012 and 2011 were ($4) million and $1 million, respectively. These items were largely offset by a $5 million increase in electric margins from changes in the recovery of electric production fuel and energy purchases expenses and an increase in weather-normalized sales volumes.

Refer to "Alliant Energy's Results of Operations—Utility Electric Margins" for details of WPL's HDD and CDD data, purchased electric capacity expenses, recoveries of electric production fuel and energy purchases expenses and sales trends.

Gas Margins—Gas margins are defined as gas operating revenues less cost of gas sold. Management believes that gas margins provide a more meaningful basis for evaluating utility operations than gas operating revenues since cost of gas sold is generally passed through to customers, and therefore, results in changes to gas operating revenues that are comparable to changes in cost of gas sold. Gas margins and Dth sales for WPL for the first quarter were as follows:

	Revenues and Costs (dollars in millions)			Dths Sold (Dths in thousands)		
	2012	2011	Change	**2012**	2011	Change
Residential	**$ 44.7**	$ 57.3	(22%)	**4,536**	5,846	(22%)
Commercial	**24.7**	32.7	(24%)	**3,069**	4,055	(24%)
Industrial	**1.7**	3.5	(51%)	**242**	506	(52%)
Retail subtotal	**71.1**	93.5	(24%)	**7,847**	10,407	(25%)
Transportation/other	**3.2**	3.6	(11%)	**5,227**	6,545	(20%)
Total revenues/sales	**74.3**	97.1	(23%)	**13,074**	16,952	(23%)
Cost of gas sold	**47.5**	63.8	(26%)			
Margins	**$ 26.8**	$ 33.3	(20%)			

First Quarter 2012 vs. First Quarter 2011 Summary—Gas margins decreased $7 million, or 20% primarily due to an estimated $6 million decrease in gas margins from changes in sales caused by weather conditions in WPL's service territory. Estimated increases (decreases) to WPL's gas margins from the impacts of weather during the first quarters of 2012 and 2011 were ($5) million and $1 million, respectively.

Refer to "Alliant Energy's Results of Operations—Utility Electric Margins" for WPL's HDD data. Refer to "Rate Matters" for discussion of retail rate cases.

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Other Operation and Maintenance Expenses—Other operation and maintenance expenses decreased $1 million primarily due to a $5 million wind site impairment charge recorded in the first quarter of 2011. This item was largely offset by higher other administrative and general expenses.

Refer to "Alliant Energy's Results of Operations—Utility Other Operation and Maintenance Expenses" for additional details of WPL's other operation and maintenance expenses.

Depreciation and Amortization Expenses—Depreciation and amortization expenses increased $2 million primarily due to property additions including higher depreciation expense recognized in the first quarter of 2012 related to the Bent Tree—Phase I wind project.

Income Taxes—Details of WPL's effective income tax rates during the first quarter were as follows:

	2012	2011
Statutory federal income tax rate	**35.0%**	35.0%
State apportionment changes	**12.3**	—
Production tax credits	**(6.2)**	(5.7)
Other items, net	**3.0**	3.2
Overall income tax rate	**44.1%**	32.5%

Refer to Note 4 of the "Combined Notes to Condensed Consolidated Financial Statements" for additional discussion of state apportionment changes and production tax credits.

LIQUIDITY AND CAPITAL RESOURCES

A summary of Alliant Energy's, IPL's and WPL's liquidity and capital resources matters is included in the 2011 Form 10-K and has not changed materially from the items reported in the 2011 Form 10-K, except as described below.

Liquidity Position—At March 31, 2012, Alliant Energy had $31 million of cash and cash equivalents, $918 million ($266 million at the parent company, $275 million at IPL and $377 million at WPL) of available capacity under their revolving credit facilities and $35 million of available capacity at IPL under its sales of accounts receivable program.

Capital Structures—Capital structures at March 31, 2012 were as follows (dollars in millions):

	Alliant Energy (Consolidated)		IPL		WPL	
Common equity	$ 2,997.5	50.0%	$ 1,360.0	47.9%	$ 1,445.5	55.4%
Preferred stock	205.1	3.4%	145.1	5.1%	60.0	2.3%
Noncontrolling interest	1.8	— %	—	— %	—	— %
Long-term debt (incl. current maturities)	2,729.6	45.6%	1,334.1	47.0%	1,082.3	41.4%
Short-term debt	57.0	1.0%	—	— %	23.3	0.9%
	$ 5,991.0	100.0%	$ 2,839.2	100.0%	$ 2,611.1	100.0%

Cash Flows—Selected information from the Condensed Consolidated Statements of Cash Flows for the first quarters of 2012 and 2011 was as follows (in millions):

	Alliant Energy		IPL		WPL	
	2012	2011	2012	2011	2012	2011
Cash and cash equivalents, Jan. 1	**$ 11.4**	$ 159.3	**$ 2.1**	$ 5.7	**$ 2.7**	$ 0.1
Cash flows from (used for):						
Operating activities	**215.0**	261.3	**78.1**	128.3	**94.3**	173.4
Investing activities	**(135.1)**	(233.3)	**(61.4)**	(109.8)	**(63.6)**	(124.3)
Financing activities	**(60.4)**	(61.2)	**4.3**	(20.3)	**(31.3)**	(48.2)
Net increase (decrease)	**19.5**	(33.2)	**21.0**	(1.8)	**(0.6)**	0.9
Cash and cash equivalents, March 31	**$ 30.9**	$ 126.1	**$ 23.1**	$ 3.9	**$ 2.1**	$ 1.0

Operating Activities -

First Quarter 2012 vs. First Quarter 2011—Alliant Energy's cash flows from operating activities decreased $46 million primarily due to lower cash flows resulting from higher inventory levels of production fuel in the first quarter of 2012, decreased collections from IPL's and WPL's customers in the first quarter of 2012 caused by the weather impacts on electric and gas retail sales, the timing of fuel-cost recoveries at IPL and $13 million of higher credits on retail electric customers' bills in Iowa in the first quarter of 2012 resulting from IPL's tax benefit rider. These items were partially offset by $54 million of higher cash flows from operations at RMT due to decreased working capital requirements associated with renewable energy projects in 2012 and 2011.

IPL's cash flows from operating activities decreased $50 million primarily due to the timing of fuel-cost recoveries, lower cash flows resulting from higher inventory levels of production fuel in the first quarter of 2012, decreased collections from IPL's customers in the first quarter of 2012 caused by the weather impacts on electric and gas retail sales and $13 million of higher credits on retail electric customers' bills in Iowa in the first quarter of 2012 resulting from the tax benefit rider. These items were partially offset by $36 million of higher cash flows from income tax refunds in the first quarter of 2012 and income tax payments in the first quarter of 2011.

WPL's cash flows from operating activities decreased $79 million primarily due to $45 million of lower cash flows from income tax payments in the first quarter of 2012 and income tax refunds in the first quarter of 2011, lower cash flows resulting from higher inventory levels of production fuel in the first quarter of 2012 and decreased collections from WPL's customers during the first quarter of 2012 caused by the weather impacts on electric and gas retail sales.

Production Fuel—MISO's dispatch of Alliant Energy's generating facilities impacts the amount of production fuel used each period at IPL and WPL. In the first quarter of 2012, lower MISO dispatch of Alliant Energy's generating facilities resulted in lower production fuel used, which contributed to increased production fuel inventory levels at IPL and WPL. Production fuel inventory levels at IPL and WPL decreased significantly in the first quarter of 2011 due to higher dispatch of Alliant Energy's generating facilities during such period. The changes in production fuel inventory levels during the first quarters of 2012 and 2011 resulted in a decrease to Alliant Energy's, IPL's and WPL's cash flows from operations of $42 million, $22 million and $20 million, respectively.

Weather Impacts—Refer to "Alliant Energy's Results of Operations," "IPL's Results of Operations" and "WPL's Results of Operations" for discussion of weather impacts on electric and gas retail sales in the first quarter of 2012 compared to the first quarter of 2011.

RMT's Working Capital Requirements—Cash flows from operations at RMT can fluctuate significantly from period to period based on the timing of cash receipts from customers and cash payments for construction activities associated with its customers' large renewable energy projects. Cash flows from operations at RMT increased significantly in the first quarter of 2012 compared to the first quarter of 2011 largely due to amounts collected in 2012 for customers' large renewable projects completed in late 2011 and early 2012. In February 2012, Alliant Energy announced plans to sell RMT in 2012.

IPL's Tax Benefit Rider—In January 2011, the IUB approved a tax benefit rider proposed by IPL, which utilizes regulatory liabilities created with tax benefits from changes in accounting methodologies and tax elections available under the Internal Revenue Code to credit bills of Iowa retail electric customers. In the first quarters of 2012 and 2011, IPL credited $20 million and $7 million, respectively, to customers' bills under the tax benefit rider. Alliant Energy and IPL currently expect approximately $81 million of credits to IPL's customers' bills in 2012 under the tax benefit rider. Refer to Note 4 of the "Combined Notes to Condensed Consolidated Financial Statements" for further discussion of IPL's tax benefit rider.

Investing Activities -

First Quarter 2012 vs. First Quarter 2011—Alliant Energy's cash flows used for investing activities decreased $98 million primarily due to $102 million of lower construction and acquisition expenditures. The lower construction and acquisition expenditures resulted from progress payments by IPL in the first quarter of 2011 for wind turbine generators that were sold to Resources in June 2011, and expenditures during the first quarter of 2011 for WPL's Bent Tree—Phase I wind project and WPL's acquisition of the remaining 25% interest in Edgewater Unit 5. These items were partially offset by expenditures during the first quarter of 2012 for emission controls projects at WPL's Columbia Units 1 and 2, IPL's Ottumwa Unit 1 and IPL's George Neal Units 3 and 4.

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IPL's cash flows used for investing activities decreased $48 million primarily due to $48 million of lower construction expenditures. The lower construction expenditures resulted from progress payments in the first quarter of 2011 for wind turbine generators that were sold to Resources in June 2011. This item was partially offset by expenditures during the first quarter of 2012 for the emission controls projects at Ottumwa Unit 1 and George Neal Units 3 and 4.

WPL's cash flows used for investing activities decreased $61 million primarily due to $59 million of lower construction and acquisition expenditures. The lower construction and acquisition expenditures resulted from expenditures during the first quarter of 2011 for the Bent Tree—Phase I wind project and the Edgewater Unit 5 purchase. These items were partially offset by expenditures during the first quarter of 2012 for emission controls projects at Columbia Units 1 and 2.

Construction and Acquisition Expenditures—Currently, there are no material changes to Alliant Energy's, IPL's and WPL's anticipated construction and acquisition expenditures from those reported in the 2011 Form 10-K.

Government Incentives for Wind Projects—Alliant Energy, IPL and WPL evaluated their options for government incentive elections for IPL's Whispering Willow—East wind project and WPL's Bent Tree—Phase I wind project and currently believe they will continue with the production tax credits incentive election for those two wind projects. Refer to "Other Matters—Other Future Considerations" for further discussion of government incentives for wind projects.

Financing Activities -

First Quarter 2012 vs. First Quarter 2011—Alliant Energy's cash flows used for financing activities decreased $1 million primarily due to changes in cash overdrafts attributable to outstanding checks that have not yet cleared the bank, largely offset by changes in the amount of commercial paper outstanding at Alliant Energy, IPL and WPL.

IPL's cash flows from financing activities increased $25 million primarily due to changes in the amount of commercial paper outstanding and changes in cash overdrafts attributable to outstanding checks that have not yet cleared the bank.

WPL's cash flows used for financing activities decreased $17 million primarily due to changes in the amount of commercial paper outstanding and changes in cash overdrafts attributable to outstanding checks that have not yet cleared the bank.

FERC Financing Authorizations—In March 2012, FERC authorized Corporate Services to issue up to $150 million in long-term debt securities and to maintain up to $200 million in short-term debt securities outstanding (including borrowings from its parent or other affiliates) during the period from March 31, 2012 through March 30, 2014. FERC also authorized Corporate Services to receive an unspecified amount of capital contributions and advances from its parent or other affiliates during the period from March 31, 2012 through March 30, 2014.

Common Stock Issuances and Capital Contributions—Refer to Note 5(b) of the "Combined Notes to Condensed Consolidated Financial Statements" for discussion of Alliant Energy's common stock issuances during the first quarter of 2012 under its equity incentive plans for employees. Refer to Note 6 of the "Combined Notes to Condensed Consolidated Financial Statements" for discussion of payments of common stock dividends by IPL and WPL to their parent company in the first quarter of 2012.

Short-term Debt—Alliant Energy's, IPL's and WPL's credit facility agreements each contain a covenant, which requires the entities to maintain certain debt-to-capital ratios in order to borrow under the credit facilities. The required debt-to-capital ratios compared to the actual debt-to-capital ratios at March 31, 2012 were as follows:

	Alliant Energy	IPL	WPL
Requirement	Less than 65%	Less than 58%	Less than 58%
Status at March 31, 2012	46%	47%	45%

Refer to Note 7(a) of the "Combined Notes to Condensed Consolidated Financial Statements" for additional information on short-term debt.

Long-term Debt—Refer to Note 7(b) of the "Combined Notes to Condensed Consolidated Financial Statements" for discussion of $25 million of commercial paper outstanding at March 31, 2012 classified as long-term debt.

Off-Balance Sheet Arrangements—A summary of Alliant Energy's off-balance sheet arrangements is included in the 2011 Form 10-K and has not changed materially from the items reported in the 2011 Form 10-K, except as described below. In April 2012, Alliant Energy exercised its option under the corporate headquarters lease and purchased the building at the expiration of the lease term for $49 million. Refer to Note 3 of the "Combined Notes to Condensed Consolidated Financial Statements" for information regarding IPL's sales of accounts receivable program including a recent extension through March 2014 of the purchase commitment from the third-party financial institution to which IPL sells its receivables. Refer to Note 11(c) of the "Combined Notes to Condensed Consolidated Financial Statements" for information regarding various guarantees and indemnifications outstanding related to Alliant Energy's prior divestiture activities, and surety bonds related to RMT's performance obligations related to various wind and solar projects.

Certain Financial Commitments—

Contractual Obligations—A summary of Alliant Energy's, IPL's and WPL's contractual obligations is included in the 2011 Form 10-K and has not changed materially from the items reported in the 2011 Form 10-K, except for the items described in Notes 7 and 11(a) of the "Combined Notes to Condensed Consolidated Financial Statements."

OTHER MATTERS

Market Risk Sensitive Instruments and Positions—Alliant Energy's, IPL's and WPL's primary market risk exposures are associated with commodity prices, investment prices and interest rates. Alliant Energy, IPL and WPL have risk management policies to monitor and assist in mitigating these market risks and use derivative instruments to manage some of the exposures. A summary of Alliant Energy's, IPL's and WPL's market risks is included in the 2011 Form 10-K and such market risks have not changed materially from those reported in the 2011 Form 10-K.

Critical Accounting Policies and Estimates—A summary of Alliant Energy's, IPL's and WPL's critical accounting policies and estimates is included in the 2011 Form 10-K and such policies and estimates have not changed materially from those reported in the 2011 10-K, except as described below.

Contingencies—Alliant Energy, IPL and WPL make assumptions and judgments each reporting period regarding the future outcome of contingent events and record loss contingency amounts for any contingent events that are both probable and reasonably estimated based upon current available information. Note 11 of the "Combined Notes to Condensed Consolidated Financial Statements" provides discussion of contingencies assessed at March 31, 2012 including various pending legal proceedings that may have a material impact on Alliant Energy's, IPL's and WPL's financial condition and results of operations.

Regulatory Assets and Regulatory Liabilities—Alliant Energy, IPL and WPL make assumptions and judgments each reporting period regarding whether their regulatory assets are probable of future recovery and their regulatory liabilities are probable future obligations. Note 1(b) of the "Combined Notes to Condensed Consolidated Financial Statements" provides details of the nature and amounts of Alliant Energy's, IPL's and WPL's regulatory assets and regulatory liabilities assessed at March 31, 2012 as well as material changes to Alliant Energy's and IPL's regulatory liabilities during the first quarter of 2012. Material changes to these regulatory liabilities during the first quarter of 2012 were largely due to IPL's tax benefit rider, which utilized $20 million of regulatory liabilities to credit IPL's Iowa retail electric customers' bills in the first quarter of 2012.

Long-Lived Assets—Alliant Energy, IPL and WPL complete periodic assessments regarding the recoverability of certain long-lived assets when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include assets within their non-regulated operations, which are proposed to be sold or are not yet generating cash flows, and assets within their regulated operations, which may not be fully recovered from IPL's and WPL's customers as a result of regulatory decisions in the future. Alliant Energy's long-lived assets within its non-regulated operations assessed in 2012 included the RMT business.

Long-Lived Assets Held for Sale—RMT—In February 2012, Alliant Energy announced plans to sell RMT in 2012. As a result, in the first quarter of 2012 Alliant Energy reclassified the RMT assets and liabilities into held for sale and its results of operations into discontinued operations. Alliant Energy performed an assessment of the carrying value of the RMT net assets held for sale as of March 31, 2012 and concluded that the forecasted selling price for the RMT business, less costs to sell, exceeded its carrying value. The forecasted selling price of RMT was estimated based upon current market information including information from recently negotiated deals in the construction industry and estimated transactional multiples from such deals. A change in the forecasted selling price could result in an impairment charge. As of March 31, 2012, the carrying value of Alliant Energy's RMT business was approximately $8 million. If Alliant Energy concludes the sale of RMT is no longer probable, it may be required to reclassify the accounting for the RMT business from assets and liabilities held for sale and discontinued operations back to continuing operations. Refer to Note 13 of the "Combined Notes to Condensed Consolidated Financial Statements" for further information regarding the RMT business.

Unbilled Revenues—Alliant Energy, IPL and WPL make assumptions and judgments each reporting period to estimate their amount of unbilled revenues. At March 31, 2012, unbilled revenues related to Alliant Energy's utility operations were $111 million ($49 million at IPL and $62 million at WPL). Note 3 of the "Combined Notes to Condensed Consolidated Financial Statements" provides discussion of IPL's unbilled revenues as of March 31, 2012 sold to a third-party financial institution related to its sales of accounts receivable program.

Pensions and Other Postretirement Benefits—Alliant Energy, IPL and WPL make assumptions and judgments periodically to estimate the obligations and costs related to their retirement plans. Note 5(a) of the "Combined Notes to Condensed Consolidated Financial Statements" provides additional details of pension and other postretirement benefits plans. Note 11(b) of the "Combined Notes to Condensed Consolidated Financial Statements" provides recent developments of the class action lawsuit filed against the Cash Balance Plan in 2008.

Income Taxes—Alliant Energy, IPL and WPL make assumptions and judgments each reporting period to estimate their income tax assets, liabilities, benefits and expenses. Alliant Energy's, IPL's and WPL's critical assumptions and judgments include projections of future taxable income used to determine their ability to utilize net operating loss and credit carryforwards prior to their expiration and the states in which such future taxable income will be apportioned.

Carryforward Utilization—Alliant Energy, IPL and WPL generated significant federal tax credits and federal and state net operating losses that are currently being carried forward. Based on current projections of future taxable income, Alliant Energy, IPL and WPL plan to utilize substantially all of these carryforwards prior to their expiration. Changes in assumptions regarding Alliant Energy's, IPL's and WPL's future taxable income could require valuation allowances in the future resulting in a material impact on their financial condition and results of operations. Refer to Note 4 of the "Combined Notes to Condensed Consolidated Financial Statements" for additional information on federal tax credit and federal and state net operating loss carryforwards as of March 31, 2012.

State Apportionment—Alliant Energy, IPL and WPL utilize state apportionment projections to record their deferred tax assets and liabilities each reporting period. Deferred tax assets and liabilities for temporary differences between the tax basis of assets and liabilities and the amounts reported in the consolidated financial statements are recorded utilizing currently enacted tax rates and estimates of future state apportionment rates expected to be in effect at the time the temporary differences reverse. These state apportionment projections are most significantly impacted by the estimated amount of revenues expected in the future from each state jurisdiction for Alliant Energy's consolidated tax group, including both its regulated operations and its non-regulated operations. Alliant Energy, IPL and WPL recorded $15 million, $8 million and $7 million, respectively, of income tax expense in the first quarter of 2012 due to changes in state apportionment projections caused by the planned sale of Alliant Energy's RMT business. A significant majority of the additional income tax expense recognized from changes in state apportionment projections were recorded at IPL and WPL due to their large deferred tax liability positions at March 31, 2012. Refer to Note 4 of the "Combined Notes to Consolidated Financial Statements" for further discussion of state apportionment impacts in the first quarter of 2012.

Other Future Considerations—A summary of Alliant Energy's, IPL's and WPL's other future considerations is included in the 2011 Form 10-K and such considerations have not changed materially from the items reported in the 2011 Form 10-K, except as described below.

Government Incentives for Wind Projects—In December 2011, the National Defense Authorization Act (NDAA) was enacted. As a result, utilities are no longer subject to a tax normalization violation if they provide the benefits of the government grant incentive to their customers over a shorter time period than the regulatory life of the project assets. This provision of the NDAA can be applied retroactively to renewable energy projects placed into service since 2009. As a result of the enactment of NDAA, Alliant Energy, IPL and WPL evaluated their options for government incentive elections for IPL's Whispering Willow—East wind project and WPL's Bent Tree—Phase I wind project and currently believe they will continue with the production tax credits incentive election for those two wind projects. Alliant Energy currently expects to elect the government grant equal to 30% of the qualified cost basis of its Franklin County wind project scheduled to be completed by the end of 2012.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Quantitative and Qualitative Disclosures About Market Risk are reported in "Other Matters—Market Risk Sensitive Instruments and Positions" in MDA.

ITEM 4. CONTROLS AND PROCEDURES

Alliant Energy's, IPL's and WPL's management evaluated, with the participation of each of Alliant Energy's, IPL's and WPL's Chief Executive Officer (CEO), Chief Financial Officer (CFO) and Disclosure Committee, the effectiveness of the design and operation of Alliant Energy's, IPL's and WPL's disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934) as of March 31, 2012 pursuant to the requirements of the Securities Exchange Act of 1934. Based on their evaluation, the CEO and the CFO concluded that Alliant Energy's, IPL's and WPL's disclosure controls and procedures were effective as of March 31, 2012.

There was no change in Alliant Energy's, IPL's and WPL's internal control over financial reporting that occurred during the quarter ended March 31, 2012 that has materially affected, or is reasonably likely to materially affect, Alliant Energy's, IPL's or WPL's internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

WPL -

Air Permitting Violation Claims—In September 2010, Sierra Club filed in the U.S. District Court for the Western District of Wisconsin a complaint against WPL, as owner and operator of Nelson Dewey and Columbia, based on allegations that modifications were made at the facilities without complying with the PSD program requirements, Title V Operating Permit requirements of the CAA and state regulatory counterparts contained within the Wisconsin SIP designed to implement the CAA. In October 2010, WPL responded to these claims related to Nelson Dewey and Columbia by filing with the U.S. District Court an answer denying the Columbia allegations and a motion to dismiss the Nelson Dewey allegations based on statute of limitations arguments. In November 2010, WPL filed a motion to dismiss the Nelson Dewey and Columbia allegations based on lack of jurisdiction. Sierra Club has responded to the motions. In January 2012, the Court reset the trial date to Dec. 10, 2012 and scheduled a status conference for Feb. 15, 2012 to receive an update on settlement progress. At the Feb. 15, 2012 status conference, the Court reaffirmed the Dec. 10, 2012 trial date and set a pre-trial schedule that allows the parties to work toward settlement.

In September 2010, Sierra Club filed in the U.S. District Court for the Eastern District of Wisconsin a complaint against WPL, as owner and operator of Edgewater, which contained similar allegations regarding air permitting violations at Edgewater. In the Edgewater complaint, additional allegations were made regarding violations of emission limits for visible emissions. In February 2011, WPL responded to these claims related to Edgewater by filing with the U.S. District Court an answer denying the allegations and a motion to dismiss the allegations based on lack of jurisdiction. In December 2011, the Court stayed all discovery and scheduling deadlines for 60 days (through Feb. 15, 2012) so that the Parties may continue settlement negotiations. In February 2012, the Court extended the stay. In April 2012, WPL and Sierra Club filed a joint settlement status report requesting the Court to stay all case management deadlines and agreeing to file a settlement status report by July 15, 2012, if no consent decree is filed by that date. WPL and Sierra Club are currently engaged in settlement discussions regarding the Nelson Dewey, Columbia and Edgewater air permitting violation claims.

In 2009, the EPA sent an NOV to WPL as an owner and the operator of Edgewater, Nelson Dewey and Columbia. The NOV alleges that the owners failed to comply with appropriate pre-construction review and permitting requirements and as a result violated the PSD program requirements, Title V Operating Permit requirements of the CAA and the Wisconsin SIP. WPL is engaged in settlement negotiations with the EPA in conjunction with the settlement negotiations with the Sierra Club discussed above.

In response to similar EPA CAA enforcement initiatives, certain utilities have elected to settle with the EPA, while others have elected to litigate. If the EPA and/or Sierra Club successfully prove their claims that projects completed in the past at Edgewater, Nelson Dewey and Columbia required either a state or federal CAA permit, WPL may, under the applicable statutes, be required to pay civil penalties in amounts of up to $37,500 per day for each violation and/or complete actions for injunctive relief. Payment of fines and/or injunctive relief could be included in a settlement outcome. Injunctive relief contained in settlements or court-ordered remedies for other utilities required the installation of emission control technology, changed operating conditions including use of alternative fuels other than coal, caps for emissions and limitations on generation including retirement of generating units, and other beneficial environmental projects. If similar remedies are required for final resolution of these matters at Edgewater, Nelson Dewey and Columbia, Alliant Energy and WPL would incur additional capital and operating expenditures. Alliant Energy and WPL are continuing to analyze the allegations and are unable to predict the impact of the allegations on their financial condition or results of operations, but believe that the outcome could be significant. WPL and the other owners of Edgewater and Columbia are exploring settlement options while simultaneously defending against these allegations. Alliant Energy and WPL believe the projects at Edgewater, Nelson Dewey and Columbia were routine or not projected to increase emissions and therefore did not violate the permitting requirements of the CAA.

ITEM 1A. RISK FACTORS

A summary of Alliant Energy's, IPL's and WPL's risk factors is included in Item 1A in the 2011 Form 10-K and such risk factors have not changed materially from the items reported in the 2011 Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

A summary of Alliant Energy common stock repurchases for the quarter ended March 31, 2012 was as follows:

Period	Total Number of Shares Purchased (a)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plan (a)
Jan. 1 to Jan. 31	13,609	$ 42.53	—	N/A
Feb. 1 to Feb. 29	28,942	43.02	—	N/A
March 1 to March 31	1,232	42.97	—	N/A
	43,783	42.87	—	

(a) Includes 3,439, 2,712 and 669 shares of Alliant Energy common stock for Jan. 1 to Jan. 31, Feb. 1 to Feb. 29, and March 1 to March 31, respectively, purchased on the open market and held in a rabbi trust under the Alliant Energy Deferred Compensation Plan (DCP). There is no limit on the number of shares of Alliant Energy common stock that may be held under the DCP, which currently does not have an expiration date. Also includes 10,170, 26,230 and 563 shares of Alliant Energy common stock for Jan. 1 to Jan. 31, Feb. 1 to Feb. 29, and March 1 to March 31, respectively, transferred from employees to Alliant Energy to satisfy tax withholding requirements in connection with the vesting of certain restricted stock under equity incentive plans.

Refer to Note 6 of the "Combined Notes to Condensed Consolidated Financial Statements" for discussion of restrictions on IPL's and WPL's distributions to their parent company.

ITEM 6. EXHIBITS

Exhibits for Alliant Energy, IPL and WPL are listed in the Exhibit Index, which is incorporated herein by reference.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, Alliant Energy Corporation, Interstate Power and Light Company and Wisconsin Power and Light Company have each duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on the 4th day of May 2012.

ALLIANT ENERGY CORPORATION Registrant	
By: /s/ Robert J. Durian Robert J. Durian	Controller and Chief Accounting Officer (Principal Accounting Officer and Authorized Signatory)
INTERSTATE POWER AND LIGHT COMPANY Registrant	
By: /s/ Robert J. Durian Robert J. Durian	Controller and Chief Accounting Officer (Principal Accounting Officer and Authorized Signatory)
WISCONSIN POWER AND LIGHT COMPANY Registrant	
By: /s/ Robert J. Durian Robert J. Durian	Controller and Chief Accounting Officer (Principal Accounting Officer and Authorized Signatory)

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ALLIANT ENERGY CORPORATION
INTERSTATE POWER AND LIGHT COMPANY
WISCONSIN POWER AND LIGHT COMPANY

Exhibit Index to Quarterly Report on Form 10-Q
For the quarter ended March 31, 2012

The following Exhibits are filed herewith.

Exhibit Number	Description
12.1	Ratio of Earnings to Fixed Charges for Alliant Energy
12.2	Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements for IPL
12.3	Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements for WPL
31.1	Certification of the Chairman, President and CEO for Alliant Energy
31.2	Certification of the Vice President and CFO for Alliant Energy
31.3	Certification of the Chairman and CEO for IPL
31.4	Certification of the Vice President and CFO for IPL
31.5	Certification of the Chairman and CEO for WPL
31.6	Certification of the Vice President and CFO for WPL
32.1	Written Statement of the CEO and CFO Pursuant to 18 U.S.C.§1350 for Alliant Energy
32.2	Written Statement of the CEO and CFO Pursuant to 18 U.S.C.§1350 for IPL
32.3	Written Statement of the CEO and CFO Pursuant to 18 U.S.C.§1350 for WPL
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* Furnished as Exhibit 101 to this report are the following documents formatted in Extensible Business Reporting Language (XBRL): (i) Alliant Energy's, IPL's and WPL's Condensed Consolidated Statements of Income for the three months ended March 31, 2012 and 2011; (ii) Alliant Energy's, IPL's and WPL's Condensed Consolidated Balance Sheets as of March 31, 2012 and Dec. 31, 2011; (iii) Alliant Energy's, IPL's and WPL's Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2012 and 2011; and (iv) the Combined Notes to Condensed Consolidated Financial Statements.

Exhibit 12.1

ALLIANT ENERGY CORPORATION

RATIO OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended Dec. 31,				
	2012	2011	2011	2010	2009	2008	2007
	(dollars in millions)						
EARNINGS:							
Net income from continuing operations attributable to Alliant Energy Corporation common shareowners	$ 39.3	$ 72.0	$323.1	$291.5	$111.6	$265.8	$415.7
Income tax expense (benefit) (a)	27.7	22.4	69.0	147.6	(6.8)	130.6	249.9
Subtotal	67.0	94.4	392.1	439.1	104.8	396.4	665.6
Fixed charges as defined	50.2	51.6	208.4	215.4	199.7	185.2	184.6
Adjustment for undistributed equity earnings	(0.8)	(1.6)	(7.0)	(5.9)	(6.7)	(6.1)	(7.8)
Less:							
Interest capitalized	1.6	—	2.7	—	—	—	—
Preferred dividend requirements of subsidiaries (pre-tax basis) (b)	6.6	8.0	22.0	27.6	17.7	27.3	29.5
Total earnings as defined	$108.2	$136.4	$568.8	$621.0	$280.1	$548.2	$812.9
FIXED CHARGES:							
Interest expense	$ 38.9	$ 40.5	$158.3	$162.8	$154.8	$125.8	$116.7
Interest capitalized	1.6	—	2.7	—	—	—	—
Estimated interest component of rent expense	3.1	3.1	25.4	25.0	27.2	32.1	38.4
Preferred dividend requirements of subsidiaries (pre-tax basis) (b)	6.6	8.0	22.0	27.6	17.7	27.3	29.5
Total fixed charges as defined	$ 50.2	$ 51.6	$208.4	$215.4	$199.7	$185.2	$184.6
Ratio of Earnings to Fixed Charges (c)	2.16	2.64	2.73	2.88	1.40	2.96	4.40

(a) Includes net interest related to unrecognized tax benefits.

(b) Preferred dividend requirements of subsidiaries (pre-tax basis) are computed by dividing the preferred dividend requirements of subsidiaries by one hundred percent minus the respective year-to-date effective income tax rate.

(c) The ratio calculation in the above table relates to Alliant Energy Corporation's continuing operations.

Exhibit 12.2

INTERSTATE POWER AND LIGHT COMPANY

RATIO OF EARNINGS TO FIXED CHARGES AND RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED DIVIDEND REQUIREMENTS

	Three Months Ended March 31,		Years Ended Dec. 31,				
	2012	2011	2011	2010	2009	2008	2007
	(dollars in millions)						
EARNINGS:							
Net income (loss)	($ 1.5)	$ 27.1	$ 139.3	$ 143.4	$ 153.0	$ 141.6	$ 290.3
Income tax expense (benefit) (a)	7.4	1.7	(3.6)	42.3	27.0	52.6	186.8
Income before income taxes	5.9	28.8	135.7	185.7	180.0	194.2	477.1
Fixed charges as defined	20.0	20.2	79.6	83.1	77.5	63.7	65.8
Total earnings as defined	$ 25.9	$ 49.0	$ 215.3	$ 268.8	$ 257.5	$ 257.9	$ 542.9
FIXED CHARGES:							
Interest expense	$ 19.7	$ 19.9	$ 78.7	$ 82.2	$ 76.5	$ 61.9	$ 64.3
Estimated interest component of rent expense	0.3	0.3	0.9	0.9	1.0	1.8	1.5
Total fixed charges as defined	$ 20.0	$ 20.2	$ 79.6	$ 83.1	$ 77.5	$ 63.7	$ 65.8
Ratio of Earnings to Fixed Charges	1.30	2.43	2.70	3.23	3.32	4.05	8.25
Preferred dividend requirements (pre-tax basis) (b)	($ 12.6)	$ 5.7	$ 14.6	$ 19.9	$ 18.1	$ 21.1	$ 25.3
Fixed charges and preferred dividend requirements	$ 7.4	$ 25.9	$ 94.2	$ 103.0	$ 95.6	$ 84.8	$ 91.1
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	3.50	1.89	2.29	2.61	2.69	3.04	5.96

(a) Includes net interest related to unrecognized tax benefits.

(b) Preferred dividend requirements (pre-tax basis) are computed by dividing the preferred dividend requirements by one hundred percent minus the respective year-to-date effective income tax rate.

Exhibit 12.3

WISCONSIN POWER AND LIGHT COMPANY

RATIO OF EARNINGS TO FIXED CHARGES AND RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED DIVIDEND REQUIREMENTS

	Three Months Ended March 31,		Years Ended Dec. 31,				
	2012	2011	2011	2010	2009	2008	2007
	(dollars in millions)						
EARNINGS:							
Net income	$ 31.9	$ 44.4	$ 163.5	$ 152.3	$ 89.5	$ 118.4	$ 113.5
Income taxes (a)	25.2	21.4	81.9	98.3	45.8	68.4	59.3
Income before income taxes	57.1	65.8	245.4	250.6	135.3	186.8	172.8
Fixed charges as defined	22.5	22.6	103.3	101.6	99.9	90.7	84.8
Adjustment for undistributed equity earnings	(1.5)	(1.1)	(6.4)	(5.6)	(7.1)	(6.1)	(6.7)
Total earnings as defined	$ 78.1	$ 87.3	$ 342.3	$ 346.6	$ 228.1	$ 271.4	$ 250.9
FIXED CHARGES:							
Interest expense	$ 20.0	$ 20.1	$ 79.9	$ 78.6	$ 74.8	$ 62.2	$ 49.6
Estimated interest component of rent expense	2.5	2.5	23.4	23.0	25.1	28.5	35.2
Total fixed charges as defined	$ 22.5	$ 22.6	$ 103.3	$ 101.6	$ 99.9	$ 90.7	$ 84.8
Ratio of Earnings to Fixed Charges	3.47	3.86	3.31	3.41	2.28	2.99	2.96
Preferred dividend requirements (pre-tax basis) (b)	$ 1.4	$ 1.2	$ 5.0	$ 5.4	$ 5.0	$ 5.2	$ 5.0
Fixed charges and preferred dividend requirements	$ 23.9	$ 23.8	$ 108.3	$ 107.0	$ 104.9	$ 95.9	$ 89.8
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	3.27	3.67	3.16	3.24	2.17	2.83	2.79

(a) Includes net interest related to unrecognized tax benefits.

(b) Preferred dividend requirements (pre-tax basis) are computed by dividing the preferred dividend requirements by one hundred percent minus the respective year-to-date effective income tax rate.

Exhibit 31.1

Certification of the Chairman, President and Chief Executive Officer for Alliant Energy Corporation

I, Patricia L. Kampling, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Alliant Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2012

/s/ Patricia L. Kampling

Patricia L. Kampling
Chairman, President and
Chief Executive Officer

Exhibit 31.2

Certification of the Vice President and Chief Financial Officer
for Alliant Energy Corporation

I, Thomas L. Hanson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Alliant Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2012

/s/ Thomas L. Hanson

Thomas L. Hanson
Vice President and
Chief Financial Officer

Exhibit 31.3

**Certification of the Chairman and Chief Executive Officer
for Interstate Power and Light Company**

I, Patricia L. Kampling, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Interstate Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2012

/s/ Patricia L. Kampling
Patricia L. Kampling
Chairman and
Chief Executive Officer

Exhibit 31.4

Certification of the Vice President and Chief Financial Officer
for Interstate Power and Light Company

I, Thomas L. Hanson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Interstate Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2012

/s/ Thomas L. Hanson
Thomas L. Hanson
Vice President and
Chief Financial Officer

Exhibit 31.5

Certification of the Chairman and Chief Executive Officer
for Wisconsin Power and Light Company

I, Patricia L. Kampling, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Wisconsin Power and Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2012

/s/ Patricia L. Kampling
Patricia L. Kampling
Chairman and
Chief Executive Officer

Exhibit 31.6

Certification of the Vice President and Chief Financial Officer
for Wisconsin Power and Light Company

I, Thomas L. Hanson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Wisconsin Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2012

/s/ Thomas L. Hanson
Thomas L. Hanson
Vice President and
Chief Financial Officer

Exhibit 32.1

Written Statement of the Chief Executive Officer and Chief Financial Officer
Pursuant to 18 U.S.C. §1350

Solely for the purposes of complying with 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, we, the undersigned Chief Executive Officer and Chief Financial Officer of Alliant Energy Corporation (the "Company"), hereby certify, based on our knowledge, that the Quarterly Report on Form 10-Q of the Company for the quarter ended March 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Patricia L. Kampling
Patricia L. Kampling
Chairman, President and Chief Executive Officer

/s/ Thomas L. Hanson
Thomas L. Hanson
Vice President and Chief Financial Officer

May 4, 2012

Exhibit 32.2

**Written Statement of the Chief Executive Officer and Chief Financial Officer
Pursuant to 18 U.S.C. §1350**

Solely for the purposes of complying with 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, we, the undersigned Chief Executive Officer and Chief Financial Officer of Interstate Power and Light Company (the "Company"), hereby certify, based on our knowledge, that the Quarterly Report on Form 10-Q of the Company for the quarter ended March 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Patricia L. Kampling
Patricia L. Kampling
Chairman and Chief Executive Officer

/s/ Thomas L. Hanson
Thomas L. Hanson
Vice President and Chief Financial Officer

May 4, 2012

Exhibit 32.3

Written Statement of the Chief Executive Officer and Chief Financial Officer
Pursuant to 18 U.S.C. §1350

Solely for the purposes of complying with 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, we, the undersigned Chief Executive Officer and Chief Financial Officer of Wisconsin Power and Light Company (the "Company"), hereby certify, based on our knowledge, that the Quarterly Report on Form 10-Q of the Company for the quarter ended March 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Patricia L. Kampling
Patricia L. Kampling
Chairman and Chief Executive Officer

/s/ Thomas L. Hanson
Thomas L. Hanson
Vice President and Chief Financial Officer

May 4, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2012

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia *(State or other jurisdiction of incorporation or organization)*	**75-1743247** *(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas** *(Address of principal executive offices)*	**75240** *(Zip code)*

(972) 934-9227

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of April 27, 2012.

Class	Shares Outstanding
No Par Value	90,030,471

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
CFTC	Commodity Futures Trading Commission
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2012	September 30, 2011
	(Unaudited) (In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,992,899	$6,816,794
Less accumulated depreciation and amortization	1,658,887	1,668,876
Net property, plant and equipment	5,334,012	5,147,918
Current assets		
Cash and cash equivalents	47,040	131,419
Accounts receivable, net	350,261	273,303
Gas stored underground	221,112	289,760
Other current assets	275,428	316,471
Total current assets	893,841	1,010,953
Goodwill and intangible assets	740,185	740,207
Deferred charges and other assets	400,689	383,793
	$7,368,727	$7,282,871
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2012 — 90,029,852 shares; September 30, 2011 — 90,296,482 shares	$ 450	$ 451
Additional paid-in capital	1,728,150	1,732,935
Retained earnings	685,206	570,495
Accumulated other comprehensive loss	(53,094)	(48,460)
Shareholders' equity	2,360,712	2,255,421
Long-term debt	1,956,213	2,206,117
Total capitalization	4,316,925	4,461,538
Current liabilities		
Accounts payable and accrued liabilities	309,864	291,205
Other current liabilities	374,123	367,563
Short-term debt	173,996	206,396
Current maturities of long-term debt	250,131	2,434
Total current liabilities	1,108,114	867,598
Deferred income taxes	1,062,488	960,093
Regulatory cost of removal obligation	414,001	428,947
Deferred credits and other liabilities	467,199	564,695
	$7,368,727	$7,282,871

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2012	2011
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 889,008	$1,077,414
Regulated transmission and storage segment	58,037	54,976
Nonregulated segment	370,763	583,531
Intersegment eliminations	(74,358)	(134,424)
	1,243,450	1,581,497
Purchased gas cost		
Natural gas distribution segment	508,206	698,410
Regulated transmission and storage segment	—	—
Nonregulated segment	374,992	563,473
Intersegment eliminations	(74,009)	(134,054)
	809,189	1,127,829
Gross profit	434,261	453,668
Operating expenses		
Operation and maintenance	110,708	114,162
Depreciation and amortization	60,272	55,467
Taxes, other than income	54,919	53,558
Asset impairment	—	19,282
Total operating expenses	225,899	242,469
Operating income	208,362	211,199
Miscellaneous income	616	26,202
Interest charges	36,660	37,875
Income from continuing operations before income taxes	172,318	199,526
Income tax expense	66,408	71,366
Income from continuing operations	105,910	128,160
Income from discontinued operations, net of tax ($1,834 and $2,642)	3,201	4,049
Net income	$ 109,111	$ 132,209
Basic earnings per share		
Income per share from continuing operations	$ 1.16	$ 1.41
Income per share from discontinued operations	0.04	0.04
Net income per share — basic	$ 1.20	$ 1.45
Diluted earnings per share		
Income per share from continuing operations	$ 1.16	$ 1.41
Income per share from discontinued operations	0.04	0.04
Net income per share — diluted	$ 1.20	$ 1.45
Cash dividends per share	$ 0.345	$ 0.340
Weighted average shares outstanding:		
Basic	90,020	90,246
Diluted	90,322	90,533

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2012	2011
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,582,300	$1,780,876
Regulated transmission and storage segment	114,796	103,983
Nonregulated segment	814,939	1,059,171
Intersegment eliminations	(167,412)	(229,271)
	2,344,623	2,714,759
Purchased gas cost		
Natural gas distribution segment	910,413	1,110,936
Regulated transmission and storage segment	—	—
Nonregulated segment	803,763	1,013,935
Intersegment eliminations	(166,696)	(228,504)
	1,547,480	1,896,367
Gross profit	797,143	818,392
Operating expenses		
Operation and maintenance	226,770	228,652
Depreciation and amortization	119,487	110,244
Taxes, other than income	98,117	93,726
Asset impairment	—	19,282
Total operating expenses	444,374	451,904
Operating income	352,769	366,488
Miscellaneous income (expense)	(1,259)	25,476
Interest charges	72,102	76,770
Income from continuing operations before income taxes	279,408	315,194
Income tax expense	107,710	115,934
Income from continuing operations	171,698	199,260
Income from discontinued operations, net of tax ($3,393 and $4,532)	5,920	6,946
Net income	$ 177,618	$ 206,206
Basic earnings per share		
Income per share from continuing operations	$ 1.89	$ 2.18
Income per share from discontinued operations	0.06	0.08
Net income per share — basic	$ 1.95	$ 2.26
Diluted earnings per share		
Income per share from continuing operations	$ 1.88	$ 2.18
Income per share from discontinued operations	0.06	0.08
Net income per share — diluted	$ 1.94	$ 2.26
Cash dividends per share	$ 0.690	$ 0.680
Weighted average shares outstanding:		
Basic	90,137	90,157
Diluted	90,440	90,455

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2012	2011
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 177,618	$ 206,206
Adjustments to reconcile net income to net cash provided by operating activities:		
Asset impairment	—	19,282
Depreciation and amortization:		
Charged to depreciation and amortization	122,532	113,297
Charged to other accounts	203	98
Deferred income taxes	102,052	115,302
Other	9,874	10,255
Net assets / liabilities from risk management activities	15,690	(17,478)
Net change in operating assets and liabilities	(67,246)	(8,491)
Net cash provided by operating activities	360,723	438,471
Cash Flows From Investing Activities		
Capital expenditures	(311,123)	(246,663)
Other, net	(3,878)	(1,535)
Net cash used in investing activities	(315,001)	(248,198)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(48,945)	(128,884)
Unwinding of Treasury lock agreements	—	27,803
Repayment of long-term debt	(2,369)	(10,066)
Cash dividends paid	(62,907)	(62,067)
Repurchase of common stock	(12,535)	—
Repurchase of equity awards	(3,509)	(3,333)
Issuance of common stock	164	7,568
Net cash used in financing activities	(130,101)	(168,979)
Net increase (decrease) in cash and cash equivalents	(84,379)	21,294
Cash and cash equivalents at beginning of period	131,419	131,952
Cash and cash equivalents at end of period	$ 47,040	$ 153,246

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2012

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other non-regulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which currently cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. In May 2011, we entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, which we currently anticipate will occur during fiscal 2012, we will operate in nine states. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

We operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2012 are not indicative of our results of operations for the full 2012 fiscal year, which ends September 30, 2012.

We have evaluated subsequent events from the March 31, 2012 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). Except as discussed in Note 6, no events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011.

Due to the pending sale of our distribution operations in our Missouri, Illinois and Iowa service areas, the financial results for these service areas are shown in discontinued operations. Accordingly, certain prior-year amounts have been reclassified to conform with the current year presentation.

During the second quarter of fiscal 2012, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

During the six months ended March 31, 2012, two new accounting standards were announced that will become applicable to the Company in future periods. The first standard requires enhanced disclosure of offsetting arrangements for financial instruments and will become effective for annual periods beginning after January 1, 2013 and for interim periods within those annual periods. The second standard indefinitely defers the effective date for amendments to the presentation of reclassifications of items out of accumulated other comprehensive income as prescribed by a previously issued standard, which were initially to be effective for interim and annual periods beginning after December 15, 2011. The adoption of these standards should not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the six months ended March 31, 2012.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities, and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of March 31, 2012 and September 30, 2011 included the following:

	March 31, 2012	September 30, 2011
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$245,096	$254,666
Merger and integration costs, net	5,998	6,242
Deferred gas costs	19,547	33,976
Regulatory cost of removal asset	10,233	8,852
Environmental costs	117	385
Rate case costs	4,503	4,862
Deferred franchise fees	333	379
Other	8,861	3,534
	$294,688	$312,896
Regulatory liabilities:		
Deferred gas costs	$ 15,232	$ 8,130
Regulatory cost of removal obligation	463,740	464,025
Other	13,090	14,025
	$492,062	$486,180

The amounts above do not include regulatory assets and liabilities related to our Missouri, Illinois and Iowa service areas, which are classified as assets held for sale as discussed in Note 5.

During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of March 31, 2012, we had deferred $0.7 million associated with the requirements of this rule which are recorded in "Other" in the regulatory assets table above.

Effective January 1, 2012, the Texas Legislature amended its Gas Utility Regulatory Act (GURA) to permit natural gas utilities to defer into a regulatory asset or liability the difference between a gas utility's actual pension and postretirement expense and the level of such expense recoverable in its existing rates. The deferred amount will become eligible for inclusion in the utility's rates in its next rate proceeding. During the quarter, we elected to utilize this provision of GURA, effective January 1, 2012, and established a regulatory asset totaling $2.5 million, which is recorded in "Other" in the regulatory assets table above. Of this amount, $1.4 million represented a reduction to operation and maintenance expense during the second quarter of fiscal 2012.

Currently, our authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and six-month periods ended March 31, 2012 and 2011:

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
	(In thousands)			
Net income	$109,111	$132,209	$177,618	$206,206
Unrealized holding gains on investments, net of tax expense of $1,203 and $477 for the three months ended March 31, 2012 and 2011 and of $1,717 and $932 for the six months ended March 31, 2012 and 2011	2,046	810	2,947	1,586
Amortization, unrealized gain and unwinding of treasury lock agreements, net of tax expense (benefit) of $9,042 and $(6,125) for the three months ended March 31, 2012 and 2011 and $8,404 and $12,579 for the six month ended March 31, 2012 and 2011	15,396	(10,427)	14,309	21,420
Net unrealized gains (losses) on cash flow hedging transactions, net of tax expense (benefit) of $(3,399) and $2,573 for the three months ended March 31, 2012 and 2011 and $(13,996) and $9,190 for the six months ended March 31, 2012 and 2011	(5,315)	4,025	(21,890)	14,375
Comprehensive income	$121,238	$126,617	$172,984	$243,587

Accumulated other comprehensive income (loss), net of tax, as of March 31, 2012 and September 30, 2011 consisted of the following unrealized gains (losses):

	March 31, 2012	September 30, 2011
	(In thousands)	
Accumulated other comprehensive income (loss):		
Unrealized holding gains on investments	$ 5,505	$ 2,558
Treasury lock agreements	(19,848)	(34,157)
Cash flow hedges	(38,751)	(16,861)
	$(53,094)	$(48,460)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the six months ended March 31, 2012 there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause payments to be accelerated when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2011-2012 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 25 percent, or 25.7 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

The primary business in our nonregulated operations is to aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. We utilize proprietary and customer-owned transportation and storage assets to serve these customers, and will seek to maximize the value of this storage capacity through the arbitrage of pricing differences that occur over time by selling financial instruments at advantageous prices to lock in a gross profit margin to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control.

As a result of these activities, our nonregulated segment is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange traded options and swap contracts with counterparties. Future contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 56 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

As of March 31, 2012, we had three Treasury lock agreements outstanding to fix the Treasury yield component of 30-year unsecured notes, which we plan to issue to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2041.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of March 31, 2012, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of March 31, 2012, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(38,340)
	Cash Flow	—	49,098
	Not designated	6,033	28,190
		6,033	38,948

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of March 31, 2012 and September 30, 2011. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $5.7 million and $28.8 million of cash held on deposit in margin accounts as of March 31, 2012 and September 30, 2011 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
March 31, 2012				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 77,441	$ 77,441
Noncurrent commodity contracts	Deferred charges and other assets	—	—	—
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(45,818)	(59,301)	(105,119)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(10,914)	(10,914)
Total		(45,818)	7,226	(38,592)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	502	137,934	138,436
Noncurrent commodity contracts	Deferred charges and other assets	—	85,951	85,951
Liability Financial Instruments				
Current commodity contracts	Other current liabilities(1)	(2,215)	(164,189)	(166,404)
Noncurrent commodity contracts	Deferred credits and other liabilities	(1)	(69,496)	(69,497)
Total		(1,714)	(9,800)	(11,514)
Total Financial Instruments		$(47,532)	$ (2,574)	$ (50,106)

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $0.8 million related to risk management liabilities that were classified as assets held for sale at March 31, 2012.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2011				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 22,396	$ 22,396
Noncurrent commodity contracts	Deferred charges and other assets	—	174	174
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(31,064)	(31,064)
Noncurrent commodity contracts	Deferred credits and other liabilities	(67,527)	(7,709)	(75,236)
Total		(67,527)	(16,203)	(83,730)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	843	67,710	68,553
Noncurrent commodity contracts	Deferred charges and other assets	998	22,379	23,377
Liability Financial Instruments				
Current commodity contracts	Other current liabilities(1)	(13,256)	(73,865)	(87,121)
Noncurrent commodity contracts	Deferred credits and other liabilities	(335)	(25,071)	(25,406)
Total		(11,750)	(8,847)	(20,597)
Total Financial Instruments		$(79,277)	$(25,050)	$(104,327)

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended March 31, 2012 and 2011 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(6.2) million and $4.1 million. For the six months ended March 31, 2012 and 2011 we recognized gains arising from fair value and cash flow hedge ineffectiveness of $2.2 million and $17.5 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2012 and 2011 is presented below.

	Three Months Ended March 31	
	2012	2011
	(In thousands)	
Commodity contracts	$ 29,090	$(1,279)
Fair value adjustment for natural gas inventory designated as the hedged item	(35,087)	5,586
Total impact on revenue	$ (5,997)	$ 4,307
The impact on revenue is comprised of the following:		
Basis ineffectiveness	$ (739)	$ (509)
Timing ineffectiveness	(5,258)	4,816
	$ (5,997)	$ 4,307

	Six Months Ended March 31	
	2012	2011
	(In thousands)	
Commodity contracts	$ 53,153	$ (3,003)
Fair value adjustment for natural gas inventory designated as the hedged item	(50,335)	21,211
Total impact on revenue	$ 2,818	$18,208
The impact on revenue is comprised of the following:		
Basis ineffectiveness	$ 102	$ 412
Timing ineffectiveness	2,716	17,796
	$ 2,818	$18,208

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market. During the six months ended March 31, 2012, we recorded a $1.7 million charge to write down nonqualifying natural gas inventory to market. We did not record a writedown for nonqualifying natural gas inventory for the six months ended March 31, 2011.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and six months ended March 31, 2012 and 2011 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended March 31, 2012			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(21,181)	$(21,181)
Loss arising from ineffective portion of commodity contracts	—	—	(238)	(238)
Total impact on revenue	—	—	(21,419)	(21,419)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(502)	—	—	(502)
Total Impact from Cash Flow Hedges	$(502)	$ —	$(21,419)	$(21,921)

	Three Months Ended March 31, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(7,328)	$ (7,328)
Loss arising from ineffective portion of commodity contracts	—	—	(233)	(233)
Total impact on revenue	—	—	(7,561)	(7,561)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(669)	—	—	(669)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total Impact from Cash Flow Hedges	$21,134	$6,000	$(7,561)	$19,573

	Six Months Ended March 31, 2012			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(32,823)	$(32,823)
Loss arising from ineffective portion of commodity contracts	—	—	(668)	(668)
Total impact on revenue	—	—	(33,491)	(33,491)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,004)	—	—	(1,004)
Total Impact from Cash Flow Hedges	$(1,004)	$ —	$(33,491)	$(34,495)

	Six Months Ended March 31, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(21,581)	$(21,581)
Loss arising from ineffective portion of commodity contracts	—	—	(677)	(677)
Total impact on revenue	—	—	(22,258)	(22,258)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,339)	—	—	(1,339)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total Impact from Cash Flow Hedges	$20,464	$6,000	$(22,258)	$ 4,206

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and six months ended March 31, 2012 and 2011. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$ 15,079	$ 6,667	$ 13,676	$ 38,092
Forward commodity contracts	(18,234)	(446)	(41,912)	1,211
Recognition of (gains) losses in earnings due to settlements:				
Treasury lock agreements	317	(17,094)	633	(16,672)
Forward commodity contracts	12,919	4,471	20,022	13,164
Total other comprehensive income (loss) from hedging, net of tax(1)	$ 10,081	$ (6,402)	$ (7,581)	$ 35,795

(1) Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in accumulated other comprehensive income (AOCI) associated with our treasury lock agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of March 31, 2012. However, the table below does not include the expected recognition in earnings of our outstanding Treasury lock agreements as these instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$ (1,266)	$(32,130)	$(33,396)
Thereafter	10,284	(6,621)	3,663
Total(1)	$ 9,018	$(38,751)	$(29,733)

(1) Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended March 31, 2012 and 2011 was an increase (decrease) in revenue of $(12.8) million and $4.0 million. For the six months ended March 31, 2012 and 2011 revenue increased (decreased) $(15.0) million and $8.2 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three and six months ended March 31, 2012, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 9 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2011.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2012 and September 30, 2011. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(2)	March 31, 2012
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 502	$ —	$ —	$ 502
Nonregulated segment	52,013	249,313	—	(287,608)	13,718
Total financial instruments	52,013	249,815	—	(287,608)	14,220
Hedged portion of gas stored underground	73,043	—	—	—	73,043
Available-for-sale securities					
Money market funds	—	3,358	—	—	3,358
Registered investment companies	38,424	—	—	—	38,424
Bonds	—	23,637	—	—	23,637
Total available-for-sale securities	38,424	26,995	—	—	65,419
Total assets	$163,480	$276,810	$ —	$(287,608)	$152,682
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 48,034	$ —	$ —	$ 48,034
Nonregulated segment	76,476	227,424	—	(293,304)	10,596
Total liabilities	$ 76,476	$275,458	$ —	$(293,304)	$ 58,630

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(3)	September 30, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,841	$ —	$ —	$ 1,841
Nonregulated segment	15,262	97,396	—	(95,156)	17,502
Total financial instruments	15,262	99,237	—	(95,156)	19,343
Hedged portion of gas stored underground	47,940	—	—	—	47,940
Available-for-sale securities					
Money market funds	—	1,823	—	—	1,823
Registered investment companies	36,444	—	—	—	36,444
Bonds	—	14,366	—	—	14,366
Total available-for-sale securities	36,444	16,189	—	—	52,633
Total assets	$99,646	$115,426	$ —	$ (95,156)	$119,916
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 81,118	$ —	$ —	$ 81,118
Nonregulated segment	22,091	115,617	—	(123,943)	13,765
Total liabilities	$22,091	$196,735	$ —	$(123,943)	$ 94,883

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences. This level also includes municipal and corporate bonds where market data for pricing is observable.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of March 31, 2012, we had $5.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $2.8 million was used to offset current risk management liabilities under master netting arrangements and the remaining $2.9 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of March 31, 2012:				
Domestic equity mutual funds	$24,471	$7,821	$ —	$32,292
Foreign equity mutual funds	5,327	805	—	6,132
Bonds	23,525	127	(15)	23,637
Money market funds	3,358	—	—	3,358
	$56,681	$8,753	$ (15)	$65,419
As of September 30, 2011:				
Domestic equity mutual funds	$27,748	$4,074	$ —	$31,822
Foreign equity mutual funds	4,597	267	(242)	4,622
Bonds	14,390	10	(34)	14,366
Money market funds	1,823	—	—	1,823
	$48,558	$4,351	$(276)	$52,633

At March 31, 2012 and September 30, 2011, our available-for-sale securities included $41.8 million and $38.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At March 31, 2012 we maintained investments in bonds that have contractual maturity dates ranging from April 2012 through July 2016.

These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

We maintained several bonds with a cumulative fair value of $4.4 million in an unrealized loss position of less than $0.1 million as of March 31, 2012. These bonds have been in an unrealized loss position for less than twelve months. Based upon our intent and ability to hold these investments, our ability to direct the source of payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that these bonds are investment grade, we do not consider this impairment to be other than temporary as of March 31, 2012.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of March 31, 2012:

	March 31, 2012
	(In thousands)
Carrying Amount	$2,210,196
Fair Value	$2,583,071

5. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals, which we currently anticipate will occur during fiscal 2012.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our condensed consolidated balance sheets at March 31, 2012 and September 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
	(In thousands)			
Operating revenues	$26,374	$35,790	$49,825	$59,523
Purchased gas cost	17,026	24,636	31,977	39,533
Gross profit	9,348	11,154	17,848	19,990
Operating expenses	4,275	4,431	8,449	8,447
Operating income	5,073	6,723	9,399	11,543
Other nonoperating expense	(38)	(32)	(86)	(65)
Income from discontinued operations before income taxes	5,035	6,691	9,313	11,478
Income tax expense	1,834	2,642	3,393	4,532
Net income	$ 3,201	$ 4,049	$ 5,920	$ 6,946

The following table presents balance sheet data related to assets held for sale.

	March 31, 2012	September 30, 2011
	(In thousands)	
Net plant, property & equipment	$126,587	$127,577
Gas stored underground	6,517	11,931
Other current assets	515	786
Deferred charges and other assets	49	277
Assets held for sale	$133,668	$140,571
Accounts payable and accrued liabilities	$ 5,404	$ 1,917
Other current liabilities	6,857	4,877
Regulatory cost of removal	7,687	10,498
Deferred credits and other liabilities	872	1,153
Liabilities held for sale	$ 20,820	$ 18,445

6. Debt

The nature and terms of our debt instruments are described in detail in Note 7 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes in the terms of our debt instruments during the six months ended March 31, 2012.

Long-term debt

Long-term debt at March 31, 2012 and September 30, 2011 consisted of the following:

	March 31, 2012	September 30, 2011
	(In thousands)	
Unsecured 10% Notes, redeemed December 2011	$ —	$ 2,303
Unsecured 5.125% Senior Notes, due January 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Medium term notes		
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term note due in installments through 2013	196	262
Total long-term debt	2,210,196	2,212,565
Less:		
Original issue discount on unsecured senior notes and debentures	(3,852)	(4,014)
Current maturities	(250,131)	(2,434)
	$1,956,213	$2,206,117

Our unsecured 10% notes were paid on their maturity date on December 31, 2011 and were not replaced. As noted above, our Unsecured 5.125% Senior Notes will mature in January 2013; accordingly, these have been classified within the current maturities of long-term debt.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $750 million commercial paper program and four committed revolving credit facilities with third-party lenders. As a result, we have approximately $985 million of working capital funding. Additionally, our $750 million unsecured credit facility has an accordion feature which, if utilized, would increase borrowing capacity to $1.0 billion. At March 31, 2012 and September 30, 2011, there was $174.0 million and $206.4 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $785 million of working capital funding, including a five-year $750 million unsecured facility, a $25 million unsecured facility and a $10 million revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.2 million at March 31, 2012. Our $25 million unsecured facility was renewed effective April 1, 2012. This facility bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin.

In addition to these third-party facilities, our regulated operations had a $350 million intercompany revolving credit facility with AEH. This facility was replaced on January 1, 2012 with a $500 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility, expiring in December 2013, with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH. Due to outstanding letters of credit and various covenants, including covenants based on working capital, the amount available to AEM under this credit facility was $82.0 million at March 31, 2012.

To supplement borrowings under this facility, AEH had a $350 million intercompany demand credit facility with AEC. This facility was replaced on January 1, 2012 with a $500 million intercompany facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. At March 31, 2012, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Debt Covenants

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2012, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 52 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

AEM is required by the financial covenants in its facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At March 31, 2012, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.97 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at March 31, 2012, AEM's net working capital was $105.9 million and its tangible net worth was $142.5 million.

In addition to these financial covenants, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity, based on our credit rating or other triggering events.

We were in compliance with all of our debt covenants as of March 31, 2012. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

7. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under our 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and six months ended March 31, 2012 and 2011 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
	(In thousands, except per share amounts)			
Basic Earnings Per Share from continuing operations				
Income from continuing operations	$105,910	$128,160	$171,698	$199,260
Less: Income from continuing operations allocated to participating securities	1,109	1,342	1,794	2,089
Income from continuing operations available to common shareholders	$104,801	$126,818	$169,904	$197,171
Basic weighted average shares outstanding	90,020	90,246	90,137	90,157
Income from continuing operations per share — Basic	$ 1.16	$ 1.41	$ 1.89	$ 2.18
Basic Earnings Per Share from discontinued operations				
Income from discontinued operations	$ 3,201	$ 4,049	$ 5,920	$ 6,946
Less: Income from discontinued operations allocated to participating securities	34	42	62	73
Income from discontinued operations available to common shareholders	$ 3,167	$ 4,007	$ 5,858	$ 6,873
Basic weighted average shares outstanding	90,020	90,246	90,137	90,157
Income from discontinued operations per share — Basic	$ 0.04	$ 0.04	$ 0.06	$ 0.08
Net income per share — Basic	$ 1.20	$ 1.45	$ 1.95	$ 2.26

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
	(In thousands, except per share amounts)			
Diluted Earnings Per Share from continuing operations				
Income from continuing operations available to common shareholders	$104,801	$126,818	$169,904	$197,171
Effect of dilutive stock options and other shares	3	3	4	5
Income from continuing operations available to common shareholders	$104,804	$126,821	$169,908	$197,176
Basic weighted average shares outstanding	90,020	90,246	90,137	90,157
Additional dilutive stock options and other shares	302	287	303	298
Diluted weighted average shares outstanding	90,322	90,533	90,440	90,455
Income from continuing operations per share — Diluted	$ 1.16	$ 1.41	$ 1.88	$ 2.18
Diluted Earnings Per Share from discontinued operations				
Income from discontinued operations available to common shareholders	$ 3,167	$ 4,007	$ 5,858	$ 6,873
Effect of dilutive stock options and other shares	—	—	—	—
Income from discontinued operations available to common shareholders	$ 3,167	$ 4,007	$ 5,858	$ 6,873
Basic weighted average shares outstanding	90,020	90,246	90,137	90,157
Additional dilutive stock options and other shares	302	287	303	298
Diluted weighted average shares outstanding	90,322	90,533	90,440	90,455
Income from discontinued operations per share — Diluted	$ 0.04	$ 0.04	$ 0.06	$ 0.08
Net income per share — Diluted	$ 1.20	$ 1.45	$ 1.94	$ 2.26

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2012 and 2011 as their exercise price was less than the average market price of the common stock during that period.

Share Repurchase Program

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. However, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company. As of March 31, 2012, 387,991 shares had been repurchased for an aggregate value of $12.5 million.

8. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and six months ended March 31, 2012 and 2011 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2012	2011	2012	2011
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,298	$ 4,257	$4,088	$3,601
Interest cost	6,678	7,055	3,466	3,203
Expected return on assets	(5,369)	(6,285)	(652)	(682)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(36)	(105)	(363)	(363)
Amortization of actuarial loss	4,143	2,748	662	86
Curtailment gain	—	(40)	—	—
Net periodic pension cost	$ 9,714	$ 7,630	$7,579	$6,223

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2012	2011	2012	2011
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 8,596	$ 8,637	$ 8,176	$ 7,202
Interest cost	13,355	13,979	6,931	6,406
Expected return on assets	(10,737)	(12,248)	(1,304)	(1,364)
Amortization of transition asset	—	—	756	756
Amortization of prior service cost	(71)	(217)	(725)	(725)
Amortization of actuarial loss	8,285	6,242	1,324	173
Curtailment gain	—	(40)	—	—
Net periodic pension cost	$ 19,428	$ 16,353	$15,158	$12,448

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2012 and 2011 are as follows:

	Pension Account Plan		Other Pension Benefits		Other Benefits	
	2012	2011	2012	2011	2012	2011
Discount rate	5.05%	5.68%	5.05%	5.39%	5.05%	5.39%
Rate of compensation increase	3.50%	4.00%	3.50%	4.00%	N/A	N/A
Expected return on plan assets	7.75%	8.25%	7.75%	8.25%	4.70%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid.

Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2012. Based upon this valuation, we contributed $23.0 million to our defined benefit pension plans during the second fiscal quarter to achieve a desirable PPA funding threshold. The need for this funding reflects the increased pension benefit obligation due to a decrease in the discount rate compared to the prior year as well as a decline in the fair value of plan assets. During the first six months of fiscal 2012, we contributed $34.2 million to our defined benefit plans and we anticipate contributing an additional $12.4 million during the remainder of the fiscal year.

We contributed $9.1 million to our other post-retirement benefit plans during the six months ended March 31, 2012. We expect to contribute a total of approximately $10 million to $15 million to these plans during the remainder of the fiscal year.

9. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2012.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky, *Billy Joe Honeycutt et al. vs. Atmos Energy Corporation, et al.*, which is related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On October 17, 2011, we filed our brief of appellants with the Kentucky Court of Appeals, appealing the verdict of the trial court. The appellees in this case subsequently filed their appellees' brief with the Court of Appeals on January 16, 2012, with our reply brief being filed with the Court on March 19, 2012.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky, *Atmos Energy Corporation et al.vs. Resource Energy Technologies, LLC and Robert Thorpe and John F. Charles*, against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009. The defendants filed a motion to dismiss the case on August 25, 2011, with Atmos Energy filing a brief in response to such motion on September 19, 2011. On March 27, 2012 the court denied the motion to dismiss.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter. However, we continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

We are a party to other litigation and environmental-related matters or claims that have arisen in the ordinary course of our business. While the results of such litigation and response actions to such environmental-related matters or claims cannot be predicted with certainty, we continue to believe the final outcome of such litigation and matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At March 31, 2012, AEH was committed to purchase 96.2 Bcf within one year, 23.5 Bcf within one to three years and 0.6 Bcf after three years under indexed contracts. AEH is committed to purchase 3.5 Bcf within one year and 0.6 Bcf within one to three years under fixed price contracts with prices ranging from $1.75 to $6.36 per Mcf. Purchases under these contracts totaled $264.3 million and $438.9 million for the three months ended March 31, 2012 and 2011 and $576.4 million and $773.1 million for the six months ended March 31, 2012 and 2011.

Our natural gas distribution divisions, except for our Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of March 31, 2012 are as follows (in thousands):

2012	$ 33,347
2013	71,496
2014	61,594
2015	—
2016	—
Thereafter	—
	$166,437

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our

Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes to the estimated storage and transportation fees for the six months ended March 31, 2012.

Regulatory Matters

As previously described in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. Since that time, we have fully cooperated with the Commission during this investigation.

The Company and the Commission entered into a stipulation and consent agreement, which was approved by the Commission on December 9, 2011, thereby resolving this investigation. The Commission's findings of violations were limited to the nonregulated operations of the Company. Under the terms of the agreement, the Company paid to the United States Treasury a total civil penalty of approximately $6.4 million and to energy assistance programs approximately $5.6 million in disgorgement of unjust profits plus interest for violations identified during the investigation. The resolution of this matter did not have a material adverse impact on the Company's financial position, results of operations or cash flows and none of the payments were charged to any of the Company's customers. In addition, none of the services the Company provides to any of its regulated or nonregulated customers were affected by the agreement.

As discussed in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in 2010, our Mid-Tex Division agreed to install 100,000 steel service line replacements by September 30, 2012. As of March 31, 2012, we had replaced 73,822 lines and are on schedule for completion in September 2012. Under the terms of the agreement, special rate recovery of the associated return, depreciation and taxes is approved for lines replaced between October 1, 2010 and September 30, 2012. Since October 1, 2010, we have spent $81.4 million on steel service line replacements.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodity Futures Trading Commission (CFTC) to establish rules and regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the SEC and CFTC have issued a number of rules and regulations, we expect additional rules and regulations to be issued, which should provide additional clarity regarding the extent of the impact of this legislation on the Company. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation and related rules and regulations. Additional reporting and disclosure obligations have been imposed upon the Company, the full extent of which will not be known until the SEC and the CFTC have completed their ongoing rulemaking process.

As of March 31, 2012, rate cases were in progress in our Mid-Tex, West Texas and Kansas service areas and annual rate filing mechanisms were in progress in our Mid-Tex and Louisiana service areas along with one infrastructure program filing in progress in our Atmos Pipeline — Texas service area. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

10. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the six months ended March 31, 2012, there were no material changes in our concentration of credit risk.

11. Segment Information

As discussed in Note 1 above, we operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- The *nonregulated segment*, which is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and six month periods ended March 31, 2012 and 2011 by segment are presented in the following tables:

	Three Months Ended March 31, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$888,685	$20,430	$334,335	$ —	$1,243,450
Intersegment revenues	323	37,607	36,428	(74,358)	—
	889,008	58,037	370,763	(74,358)	1,243,450
Purchased gas cost	508,206	—	374,992	(74,009)	809,189
Gross profit	380,802	58,037	(4,229)	(349)	434,261
Operating expenses					
Operation and maintenance	89,443	15,847	5,769	(351)	110,708
Depreciation and amortization	51,755	7,792	725	—	60,272
Taxes, other than income	50,313	3,915	691	—	54,919
Total operating expenses	191,511	27,554	7,185	(351)	225,899
Operating income (loss)	189,291	30,483	(11,414)	2	208,362
Miscellaneous income (expense)	733	(56)	567	(628)	616
Interest charges	28,833	7,614	839	(626)	36,660
Income (loss) from continuing operations before income taxes	161,191	22,813	(11,686)	—	172,318
Income tax expense (benefit)	62,890	8,193	(4,675)	—	66,408
Income (loss) from continuing operations	98,301	14,620	(7,011)	—	105,910
Income from discontinued operations, net of tax	3,201	—	—	—	3,201
Net income (loss)	$101,502	$14,620	$ (7,011)	$ —	$ 109,111
Capital expenditures	$114,402	$38,871	$ 3,456	$ —	$ 156,729

	Three Months Ended March 31, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,077,178	$21,597	$482,722	$ —	$1,581,497
Intersegment revenues	236	33,379	100,809	(134,424)	—
	1,077,414	54,976	583,531	(134,424)	1,581,497
Purchased gas cost	698,410	—	563,473	(134,054)	1,127,829
Gross profit	379,004	54,976	20,058	(370)	453,668
Operating expenses					
Operation and maintenance	92,266	15,231	7,035	(370)	114,162
Depreciation and amortization	48,555	5,798	1,114	—	55,467
Taxes, other than income	50,088	4,113	(643)	—	53,558
Asset impairment	—	—	19,282	—	19,282
Total operating expenses	190,909	25,142	26,788	(370)	242,469
Operating income (loss)	188,095	29,834	(6,730)	—	211,199
Miscellaneous income	20,156	5,861	306	(121)	26,202
Interest charges	29,605	8,085	306	(121)	37,875
Income (loss) from continuing operations before income taxes	178,646	27,610	(6,730)	—	199,526
Income tax expense (benefit)	64,085	9,871	(2,590)	—	71,366
Income (loss) from continuing operations	114,561	17,739	(4,140)	—	128,160
Income from discontinued operations, net of tax	4,049	—	—	—	4,049
Net income (loss)	$ 118,610	$17,739	$ (4,140)	$ —	$ 132,209
Capital expenditures	$ 109,762	$11,818	$ 1,921	$ —	$ 123,501

	Six Months Ended March 31, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,581,753	$ 39,870	$723,000	$ —	$2,344,623
Intersegment revenues	547	74,926	91,939	(167,412)	—
	1,582,300	114,796	814,939	(167,412)	2,344,623
Purchased gas cost	910,413	—	803,763	(166,696)	1,547,480
Gross profit	671,887	114,796	11,176	(716)	797,143
Operating expenses					
Operation and maintenance	182,857	32,812	11,820	(719)	226,770
Depreciation and amortization	102,586	15,443	1,458	—	119,487
Taxes, other than income	88,792	7,699	1,626	—	98,117
Total operating expenses	374,235	55,954	14,904	(719)	444,374
Operating income (loss)	297,652	58,842	(3,728)	3	352,769
Miscellaneous income (expense)	(1,023)	(336)	603	(503)	(1,259)
Interest charges	56,688	14,823	1,091	(500)	72,102
Income (loss) from continuing operations before income taxes	239,941	43,683	(4,216)	—	279,408
Income tax expense (benefit)	93,735	15,649	(1,674)	—	107,710
Income (loss) from continuing operations	146,206	28,034	(2,542)	—	171,698
Income from discontinued operations, net of tax	5,920	—	—	—	5,920
Net income (loss)	$ 152,126	$ 28,034	$ (2,542)	$ —	$ 177,618
Capital expenditures	$ 243,135	$ 62,991	$ 4,997	$ —	$ 311,123

	Six Months Ended March 31, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,780,439	$ 42,830	$ 891,490	$ —	$2,714,759
Intersegment revenues	437	61,153	167,681	(229,271)	—
	1,780,876	103,983	1,059,171	(229,271)	2,714,759
Purchased gas cost	1,110,936	—	1,013,935	(228,504)	1,896,367
Gross profit	669,940	103,983	45,236	(767)	818,392
Operating expenses					
Operation and maintenance	181,495	30,805	17,119	(767)	228,652
Depreciation and amortization	96,449	11,597	2,198	—	110,244
Taxes, other than income	84,536	7,666	1,524	—	93,726
Asset impairment	—	—	19,282	—	19,282
Total operating expenses	362,480	50,068	40,123	(767)	451,904
Operating income	307,460	53,915	5,113	—	366,488
Miscellaneous income	19,458	5,579	596	(157)	25,476
Interest charges	59,302	16,149	1,476	(157)	76,770
Income from continuing operations before income taxes	267,616	43,345	4,233	—	315,194
Income tax expense	98,634	15,504	1,796	—	115,934
Income from continuing operations	168,982	27,841	2,437	—	199,260
Income from discontinued operations, net of tax	6,946	—	—	—	6,946
Net income	$ 175,928	$ 27,841	$ 2,437	$ —	$ 206,206
Capital expenditures	$ 219,261	$ 24,557	$ 2,845	$ —	$ 246,663

Balance sheet information at March 31, 2012 and September 30, 2011 by segment is presented to reflect our business structure as of March 31, 2012 in the following tables.

	March 31, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,382,291	$ 886,507	$ 65,214	$ —	$5,334,012
Investment in subsidiaries	674,594	—	(2,096)	(672,498)	—
Current assets					
Cash and cash equivalents	40,140	—	6,900	—	47,040
Assets from risk management activities	502	—	2,877	—	3,379
Other current assets	632,486	13,278	399,389	(201,731)	843,422
Intercompany receivables	584,018	—	—	(584,018)	—
Total current assets	1,257,146	13,278	409,166	(785,749)	893,841
Intangible assets	—	—	185	—	185
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	—	—	10,841	—	10,841
Deferred charges and other assets	366,329	13,203	10,316	—	389,848
	$7,253,268	$1,045,369	$528,337	$(1,458,247)	$7,368,727
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,360,712	$ 293,135	$381,459	$ (674,594)	$2,360,712
Long-term debt	1,956,147	—	66	—	1,956,213
Total capitalization	4,316,859	293,135	381,525	(674,594)	4,316,925
Current liabilities					
Current maturities of long-term debt	250,000	—	131	—	250,131
Short-term debt	371,996	—	—	(198,000)	173,996
Liabilities from risk management activities	47,281	—	5,296	—	52,577
Other current liabilities	507,354	6,309	119,382	(1,635)	631,410
Intercompany payables	—	551,330	32,688	(584,018)	—
Total current liabilities	1,176,631	557,639	157,497	(783,653)	1,108,114
Deferred income taxes	890,455	188,936	(16,903)	—	1,062,488
Noncurrent liabilities from risk management activities	1	—	5,300	—	5,301
Regulatory cost of removal obligation	414,001	—	—	—	414,001
Deferred credits and other liabilities	455,321	5,659	918	—	461,898
	$7,253,268	$1,045,369	$528,337	$(1,458,247)	$7,368,727

	September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,248,198	$ 838,302	$ 61,418	$ —	$5,147,918
Investment in subsidiaries	670,993	—	(2,096)	(668,897)	—
Current assets					
Cash and cash equivalents	24,646	—	106,773	—	131,419
Assets from risk management activities	843	—	17,501	—	18,344
Other current assets	655,716	15,413	386,215	(196,154)	861,190
Intercompany receivables	569,898	—	—	(569,898)	—
Total current assets	1,251,103	15,413	510,489	(766,052)	1,010,953
Intangible assets	—	—	207	—	207
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	998	—	—	—	998
Deferred charges and other assets	353,960	18,028	10,807	—	382,795
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,255,421	$ 265,102	$405,891	$ (670,993)	$2,255,421
Long-term debt	2,205,986	—	131	—	2,206,117
Total capitalization	4,461,407	265,102	406,022	(670,993)	4,461,538
Current liabilities					
Current maturities of long-term debt	2,303	—	131	—	2,434
Short-term debt	387,691	—	—	(181,295)	206,396
Liabilities from risk management activities	11,916	—	3,537	—	15,453
Other current liabilities	474,783	10,369	170,926	(12,763)	643,315
Intercompany payables	—	543,084	26,814	(569,898)	—
Total current liabilities	876,693	553,453	201,408	(763,956)	867,598
Deferred income taxes	789,649	173,351	(2,907)	—	960,093
Noncurrent liabilities from risk management activities	67,862	—	10,227	—	78,089
Regulatory cost of removal obligation	428,947	—	—	—	428,947
Deferred credits and other liabilities	473,602	12,218	786	—	486,606
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of March 31, 2012, the related condensed consolidated statements of income for the three-month and six-month periods ended March 31, 2012 and 2011, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2012 and 2011. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2011, and the related consolidated statements of income, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated November 22, 2011, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of September 30, 2011, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
May 3, 2012

Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

INTRODUCTION

The following discussion should be read in conjunction with the condensed consolidated financial statements in this Quarterly Report on Form 10-Q and Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ended September 30, 2011.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas currently located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. In May 2011, we entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, which we currently anticipate will occur during fiscal 2012, we will operate in nine states.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 11, we operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the six months ended March 31, 2012.

RESULTS OF OPERATIONS

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 62 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

Additionally, the seasonality of our business impacts our working capital differently at various times during the year. Typically, our accounts receivable, accounts payable and short-term debt balances peak by the end of January and then start to decline, as customers begin to pay their winter heating bills. Gas stored underground, particularly in our natural gas distribution segment, typically peaks in November and declines as we utilize storage gas to serve our customers.

We reported net income of $109.1 million, or $1.20 per diluted share for the three months ended March 31, 2012, compared with net income of $132.2 million or $1.45 per diluted share in the prior year. Excluding the impact of unrealized margins, diluted earnings per share decreased $0.19 compared with the prior-year quarter. Results for the prior-year period were influenced by the net positive impact of several one-time items totaling $11.1 million, or $0.12 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to a cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a previously planned debt offering.
- $19.3 million unfavorable impact related to the non-cash impairment of certain assets in our nonregulated business.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

After excluding the impact of unrealized margins and the one-time items, net income and diluted earnings per share for the three months ended March 31, 2012 decreased $6.4 million, or $0.07 per diluted share when compared to the prior-year period, primarily due to lower earnings in our nonregulated segment due to historically warm winter weather and unfavorable natural gas market conditions. Included in the current quarter amount is net income from discontinued operations of $3.2 million, or $0.04 per diluted share associated with the pending sale of our Missouri, Illinois and Iowa service areas, a decrease of $0.8 million or $0.00 per diluted share compared with the prior-year quarter.

During the six months ended March 31, 2012, we earned $177.6 million or $1.94 per diluted share, which represents a 14 percent decrease in net income and diluted net income per share compared with the prior-year period. Results for the prior-year period were influenced by the net positive impact of several one-time items totaling $11.1 million, or $0.12 per diluted share. Excluding the impact of these one-time items and unrealized margins in our nonregulated operations, we earned $172.3 million, or $1.88 per diluted share for the six months ended March 31, 2012, compared to $196.8 million, or $2.16 in the prior-year period. Included in the current period amount is net income from discontinued operations of $5.9 million, or $0.06 per diluted share associated with the pending sale of our Missouri, Illinois and Iowa service areas, a decrease of $1.0 million or $0.02 per diluted share compared with the prior-year period.

Our quarter-to-date and year-to-date results were unfavorably impacted by substantially warmer winter weather and an abundance of natural gas supply. The impact of these conditions was most significantly realized in our nonregulated operations, which experienced a $23.0 million six-month period-over-period decrease in net income, excluding the impact of one-time items and unrealized margins. These market conditions also contributed to a 10 percent decrease in throughput in our natural gas distribution segment and lower through-system transportation rates earned on our regulated intrastate pipeline for the six months ended March 31, 2012 compared to the six months ended March 31, 2011. However, the impact on our regulated operations was not as significant due to favorable rate designs, which substantially mitigated the effects of relatively warm weather in most of our natural gas distribution service areas and the favorable impact of rate case increases experienced in both our natural gas distribution and regulated transmission and storage segments.

During the fiscal second quarter, we undertook several steps to grow earnings in our regulated operations. In our natural gas distribution segment, we initiated seven rate proceedings requesting a total of $68.7 million in additional annual operating income and, in April 2012, we completed an annual rate filing for Atmos Pipeline-Texas (APT) that should increase annual operating income by $14.7 million. Further, we announced two significant pipeline expansion projects whereby APT will spend $150 million over the next two fiscal years to increase its ability to secure new long-term gas supply on a firm and reliable basis and to enhance the reliability of APT's service to our Mid-Tex Division in certain critical locations.

During the second fiscal quarter, we completed the annual evaluation of the funded status of our qualified defined benefit plans as of January 1, 2012 as required by the Pension Protection Act of 2006 (PPA). As a result of lower asset returns and a year-over-year 92 basis point decline in the discount rate used to value our pension liabilities, we were required to contribute $23.0 million into the plans. For the six months ended March 31, 2012, we contributed $34.2 million into these plans and expect to contribute an additional $12.4 million for the remainder of the fiscal year. Additionally, we contributed $9.1 million into our postretirement medical plans during the six months ended March 31, 2012 and expect to contribute between $10 million and $15 million for the remainder of the fiscal year. We believe our cash flows from operations are sufficient to fund these contributions.

Consolidated Results

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2012 and 2011:

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
	(In thousands, except per share data)			
Operating revenues	$1,243,450	$1,581,497	$2,344,623	$2,714,759
Gross profit	434,261	453,668	797,143	818,392
Operating expenses	225,899	242,469	444,374	451,904
Operating income	208,362	211,199	352,769	366,488
Miscellaneous income (expense)	616	26,202	(1,259)	25,476
Interest charges	36,660	37,875	72,102	76,770
Income from continuing operations before income taxes	172,318	199,526	279,408	315,194
Income tax expense	66,408	71,366	107,710	115,934
Income from continuing operations	105,910	128,160	171,698	199,260
Income from discontinued operations, net of tax	3,201	4,049	5,920	6,946
Net income	$ 109,111	$ 132,209	$ 177,618	$ 206,206
Diluted net income per share from continuing operations	$ 1.16	$ 1.41	$ 1.88	$ 2.18
Diluted net income per share from discontinued operations	0.04	0.04	0.06	0.08
Diluted net income per share	$ 1.20	$ 1.45	$ 1.94	$ 2.26

Our consolidated net income during the three and six month periods ended March 31, 2012 and 2011 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2012	2011	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$ 98,301	$114,561	$(16,260)
Regulated transmission and storage segment	14,620	17,739	(3,119)
Nonregulated segment	(7,011)	(4,140)	(2,871)
Net income from continuing operations	105,910	128,160	(22,250)
Net income from discontinued operations	3,201	4,049	(848)
Net income	$109,111	$132,209	$(23,098)

	Six Months Ended March 31		
	2012	2011	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$146,206	$168,982	$(22,776)
Regulated transmission and storage segment	28,034	27,841	193
Nonregulated segment	(2,542)	2,437	(4,979)
Net income from continuing operations	171,698	199,260	(27,562)
Net income from discontinued operations	5,920	6,946	(1,026)
Net income	$177,618	$206,206	$(28,588)

Regulated operations contributed 106 percent and 101 percent to our consolidated net income for the three and six month periods ended March 31, 2012. The following tables segregate our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended March 31		
	2012	2011	Change
	(In thousands, except per share data)		
Regulated operations	$112,921	$132,300	$(19,379)
Nonregulated operations	(7,011)	(4,140)	(2,871)
Net income from continuing operations	105,910	128,160	(22,250)
Net income from discontinued operations	3,201	4,049	(848)
Net income	$109,111	$132,209	$(23,098)
Diluted EPS from continuing regulated operations	$ 1.23	$ 1.45	$ (0.22)
Diluted EPS from nonregulated operations	(0.07)	(0.04)	(0.03)
Diluted EPS from continuing operations	1.16	1.41	(0.25)
Diluted EPS from discontinued operations	0.04	0.04	—
Consolidated diluted EPS	$ 1.20	$ 1.45	$ (0.25)

	Six Months Ended March 31		
	2012	2011	Change
	(In thousands, except per share data)		
Regulated operations	$174,240	$196,823	$(22,583)
Nonregulated operations	(2,542)	2,437	(4,979)
Net income from continuing operations	171,698	199,260	(27,562)
Net income from discontinued operations	5,920	6,946	(1,026)
Net income	$177,618	$206,206	$(28,588)
Diluted EPS from continuing regulated operations	$ 1.91	$ 2.15	$ (0.24)
Diluted EPS from nonregulated operations	(0.03)	0.03	(0.06)
Diluted EPS from continuing operations	1.88	2.18	(0.30)
Diluted EPS from discontinued operations	0.06	0.08	(0.02)
Consolidated diluted EPS	$ 1.94	$ 2.26	$ (0.32)

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for over 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
Virginia	January — December

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources. Conversely, lower gas costs reduce our collection risk and reduce the need to utilize short-term borrowings to fund our working capital needs.

As discussed above, in May 2011, we entered into a definitive agreement to sell substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables as discontinued operations and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

Three Months Ended March 31, 2012 compared with Three Months Ended March 31, 2011

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2012 and 2011 are presented below.

	Three Months Ended March 31		
	2012	2011	Change
	(In thousands, unless otherwise noted)		
Gross profit	$380,802	$379,004	$ 1,798
Operating expenses	191,511	190,909	602
Operating income	189,291	188,095	1,196
Miscellaneous income	733	20,156	(19,423)
Interest charges	28,833	29,605	(772)
Income from continuing operations before income taxes	161,191	178,646	(17,455)
Income tax expense	62,890	64,085	(1,195)
Income from continuing operations	98,301	114,561	(16,260)
Income from discontinued operations, net of tax	3,201	4,049	(848)
Net income	$101,502	$118,610	$(17,108)
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	103,169	132,517	(29,348)
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	36,877	37,378	(501)
Consolidated natural gas distribution throughput from continuing operations — MMcf	140,046	169,895	(29,849)
Consolidated natural gas distribution throughput from discontinued operations — MMcf	4,848	6,406	(1,558)
Total consolidated natural gas distribution throughput — MMcf	144,894	176,301	(31,407)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.43	$ 0.47	$ (0.04)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 4.94	$ 5.28	$ (0.34)

The $1.8 million increase in natural gas distribution gross profit was primarily due to a $6.4 million net increase in rate adjustments, primarily in our Mid-Tex, Mississippi and Louisiana service areas, combined with a $1.0 million increase in customers, primarily in our Mid-Tex service area.

These increases were partially offset by a $5.9 million decrease in revenue-related taxes in our Mid-Tex, West Texas and Mississippi service areas, primarily due to lower revenues on which the tax is calculated.

Results for the second fiscal quarter were also unfavorably impacted by significantly warmer winter weather, which resulted in an 18 percent decrease in total consolidated throughput compared to the prior year. However, the impact to gross profit was mitigated by favorable rate designs that substantially lessened the impact of warm weather in most of our natural gas distribution service areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $0.6 million primarily due to the following:

- $3.2 million increase in depreciation and amortization associated with an increase in our net plant as a result of our capital investments in the prior year.

- $1.1 million net increase in legal and other administrative costs.
- $1.2 million increase in software maintenance costs.

These increases were partially offset by the following:

- $2.0 million decrease in revenue-related taxes. When combined with the $5.9 million decrease in associated revenue taxes included in gross margin, we experienced a net $3.9 million quarter-over-quarter decrease in operating income.
- $1.4 million decrease due to the establishment of a regulatory asset in Texas for pension and post-retirement costs.
- $1.0 million decrease in operating expenses due to increased capital spending and warmer weather allowing us time to complete more capital work than in the prior year.

Net income for this segment for the prior-year quarter was favorably impacted by a $21.8 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended March 31, 2012 and 2011. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2012	2011	Change
	(In thousands)		
Mid-Tex	$ 88,301	$ 82,476	$ 5,825
Kentucky/Mid-States	24,655	28,837	(4,182)
Louisiana	22,470	23,235	(765)
West Texas	17,989	19,280	(1,291)
Mississippi	17,537	18,004	(467)
Colorado-Kansas	13,982	15,250	(1,268)
Other	4,357	1,013	3,344
Total	$189,291	$188,095	$ 1,196

Six Months Ended March 31, 2012 compared with Six Months Ended March 31, 2011

Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2012 and 2011 are presented below.

	Six Months Ended March 31		
	2012	2011	Change
	(In thousands, unless otherwise noted)		
Gross profit	$671,887	$669,940	$ 1,947
Operating expenses	374,235	362,480	11,755
Operating income	297,652	307,460	(9,808)
Miscellaneous income (expense)	(1,023)	19,458	(20,481)
Interest charges	56,688	59,302	(2,614)
Income from continuing operations before income taxes	239,941	267,616	(27,675)
Income tax expense	93,735	98,634	(4,899)
Income from continuing operations	146,206	168,982	(22,776)
Income from discontinued operations, net of tax	5,920	6,946	(1,026)
Net income	$152,126	$175,928	$(23,802)
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	188,059	216,654	(28,595)
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	69,709	69,596	113
Consolidated natural gas distribution throughput from continuing operations — MMcf	257,768	286,250	(28,482)
Consolidated natural gas distribution throughput from discontinued operations — MMcf	8,874	10,595	(1,721)
Total consolidated natural gas distribution throughput — MMcf	266,642	296,845	(30,203)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.44	$ 0.48	$ (0.04)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 4.87	$ 5.14	$ (0.27)

The $1.9 million increase in natural gas distribution gross profit was primarily due to an $11.0 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Mississippi, Kentucky and West Texas service areas.

These increases were partially offset by the following:

- $2.9 million decrease due to a 10 percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather in the current quarter compared to the same period last year in most of our service areas.
- $5.6 million decrease in revenue-related taxes in our Mid-Tex, West Texas and Mississippi service areas, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $11.8 million primarily due to the following:

- $6.1 million increase in depreciation and amortization and a $5.5 million increase in ad valorem taxes associated with an increase in our net plant as a result of our capital investments in the prior year.

• $7.6 million net increase in legal and other administrative costs.

• $1.8 million increase in software maintenance costs.

These increases were partially offset by the following:

• $4.0 million decrease in operating expenses due to increased capital spending and warmer weather allowing us time to complete more capital work than in the prior year.

• $1.8 million decrease in revenue-related taxes. When combined with the $5.6 million decrease in associated revenue taxes included in gross margin, we experienced a net $3.8 million year-over-year decrease in operating income.

• $1.4 million decrease associated with the aforementioned regulatory asset.

Net income from the prior-year period also reflects the aforementioned Treasury lock gain and income tax benefit.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the six months ended March 31, 2012 and 2011. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2012	2011	Change
	(In thousands)		
Mid-Tex	$136,750	$139,915	$(3,165)
Kentucky/Mid-States	40,973	45,690	(4,717)
Louisiana	37,671	38,196	(525)
West Texas	28,664	28,800	(136)
Mississippi	27,669	28,219	(550)
Colorado-Kansas	22,161	22,952	(791)
Other	3,764	3,688	76
Total	$297,652	$307,460	$(9,808)

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the six months ended March 31, 2012 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $8.0 million resulting from ratemaking activity became effective in the six months ended March 31, 2012 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Rate case filings	$ 545
Infrastructure programs	3,744
Annual rate filing mechanisms	3,505
Other rate activity	167
	$7,961

Additionally, the following ratemaking efforts were in progress during the second quarter of fiscal 2012 but had not been completed as of March 31, 2012.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Mid-Tex	Rate Case	RRC	$45,980
West Texas	Rate Case	RRC	11,137
Colorado-Kansas	Rate Case	Kansas	6,134
Mid-Tex	Dallas Annual Rate Review	RRC	2,545
Louisiana	Rate Stabilization Clause	LGS	1,823
Kentucky/Mid-States	PRP	Georgia	1,079
Louisiana	Rate Stabilization Clause	TransLa	—
			$68,698

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate case that was completed during the six months ended March 31, 2012.

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2012 Rate Case Filings:			
West Texas — Environs	Texas	$545	11/08/2011
Total 2012 Rate Case Filings		$545	

Infrastructure Programs

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia, Missouri and Kentucky. The following table summarizes our infrastructure program filings with effective dates occurring during the six months ended March 31, 2012.

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2012 Infrastructure Programs:				
Kentucky/Mid-States — Georgia	09/2010	$ 7,160	$1,215	10/01/2011
Kentucky/Mid-States — Kentucky	09/2012	17,347	2,529	10/01/2011
Total 2012 Infrastructure Programs		$24,507	$3,744	

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and the Georgia service area in our Kentucky/Mid-States Division. The Company is requesting new annual rate filing mechanisms as part of our ongoing rate cases in our Mid-Tex and West Texas divisions to replace the annual mechanisms that expired for significant portions of these service areas in 2011. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the six months ended March 31, 2012.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2012 Filings:				
Kentucky/Mid-States	Georgia	09/30/2011	$ (818)	02/01/2012
Mississippi	Mississippi	06/30/2011	4,323	01/11/2012
Total 2012 Filings			$3,505	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the six months ended March 31, 2012:

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2012 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem(1)	$167	01/14/2012
Total 2012 Other Rate Activity			$167	

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas area's base rates.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline–Texas Division. The Atmos Pipeline–Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline–Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, as a regulated pipeline, the operations of the Atmos Pipeline–Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Three Months Ended March 31, 2012 compared with Three Months Ended March 31, 2011

Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2012 and 2011 are presented below.

	Three Months Ended March 31		
	2012	2011	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 39,114	$ 33,096	$ 6,018
Third-party transportation	14,309	16,811	(2,502)
Storage and park and lend services	1,867	2,219	(352)
Other	2,747	2,850	(103)
Gross profit	58,037	54,976	3,061
Operating expenses	27,554	25,142	2,412
Operating income	30,483	29,834	649
Miscellaneous income (expense)	(56)	5,861	(5,917)
Interest charges	7,614	8,085	(471)
Income before income taxes	22,813	27,610	(4,797)
Income tax expense	8,193	9,871	(1,678)
Net income	$ 14,620	$ 17,739	$ (3,119)
Gross pipeline transportation volumes — MMcf	176,361	174,471	1,890
Consolidated pipeline transportation volumes — MMcf	109,626	93,493	16,133

The $3.1 million increase in regulated transmission and storage gross profit compared to the prior-year quarter was primarily a result of rate design changes approved in the rate case in the prior year. The current rate design allows us to recover fixed costs associated with transportation and storage services through monthly customer charges rather than through a volumetric charge, which should allow us to earn margin more ratably during the fiscal year. Therefore, despite an 18 percent decrease in throughput to our Mid-Tex Division, we experienced an 18 percent increase in gross profit from Mid-Tex transportation.

For the quarter, the enhanced rate design resulted in an $8.4 million increase in gross profit compared to the prior-year quarter. This increase was partially offset by the following:

- $3.0 million decrease associated with lower throughput to our Mid-Tex Division.
- $1.5 million decrease in third-party transportation. Throughput associated with third-party transportation increased 17 percent due to the execution of new delivery contracts with local producers in the Barnett Shale region. However, these increases were more than offset by lower transportation rates.

Operating expenses increased $2.4 million primarily due to the following:

- $0.5 million increase due to higher pipeline maintenance costs.
- $2.0 million increase due to higher depreciation expense, resulting from the rate case and a higher investment in net plant.

Net income for this segment for the prior-year quarter was favorably impacted by a $6.0 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks.

On April 10, 2012, the RRC approved the Atmos Pipeline — Texas GRIP filing that was filed in February 2012. The Commission approved an annual operating income increase of $14.7 million that went into effect with bills rendered on and after April 10, 2012.

Six Months Ended March 31, 2012 compared with Six Months Ended March 31, 2011

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2012 and 2011 are presented below.

	Six Months Ended March 31		
	2012	2011	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 76,457	$ 60,631	$15,826
Third-party transportation	29,248	33,323	(4,075)
Storage and park and lend services	3,673	4,389	(716)
Other	5,418	5,640	(222)
Gross profit	114,796	103,983	10,813
Operating expenses	55,954	50,068	5,886
Operating income	58,842	53,915	4,927
Miscellaneous income (expense)	(336)	5,579	(5,915)
Interest charges	14,823	16,149	(1,326)
Income before income taxes	43,683	43,345	338
Income tax expense	15,649	15,504	145
Net income	$ 28,034	$ 27,841	$ 193
Gross pipeline transportation volumes — MMcf	337,190	327,649	9,541
Consolidated pipeline transportation volumes — MMcf	214,663	193,334	21,329

The $10.8 million increase in regulated transmission and storage gross profit compared to the prior-year period was primarily a result of the previously discussed rate design changes approved in the rate case in the prior year. Therefore, despite a nine percent decrease in throughput to our Mid-Tex Division, we experienced a 26 percent increase in gross profit from Mid-Tex transportation.

For the year-to-date period, the enhanced rate design resulted in a $16.9 million increase in gross profit compared to the prior-year period. This increase was partially offset by the following:

- $2.5 million decrease associated with lower throughput to our Mid-Tex Division.
- $2.5 million decrease in third-party transportation. Throughput associated with third-party transportation increased 11 percent due to the execution of new delivery contracts with local producers in the Barnett Shale region. However, these increases were more than offset by lower transportation rates.

Operating expenses increased $5.9 million primarily due to the following:

- $1.8 million increase due to higher pipeline maintenance costs.
- $3.8 million increase due to higher depreciation expense, resulting from the rate case and a higher investment in net plant.

Net income from the prior-year period also reflects the aforementioned Treasury lock gain.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. This business is significantly influenced by competitive factors in the industry, general economic conditions and other factors that could affect the demand for natural gas. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of gas used to serve those customers. Further, delivered gas margins can be affected by the price of natural gas in the different locations where we buy and sell gas.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. The majority of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions. These margins are influenced by natural gas market conditions including, but not limited to, the price of natural gas, demand for natural gas, the level of domestic natural gas inventory levels and the level of volatility between current (spot) and future natural gas prices. These margins are also impacted by our ability to minimize the demand fees paid to contract for storage capacity.

Higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices may also cause customers to conserve or use alternative energy sources. Lower natural gas prices generally reduce these risks.

The level of volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads and basis differentials from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Conversely, a lack of price volatility reduces opportunities to create value from arbitrage spreads and basis differentials.

Our nonregulated segment manages its exposure to natural gas commodity price risk through a combination of physical storage and financial instruments. Therefore, results for this segment will include unrealized gains or losses on its net physical gas position and the related financial instruments used to manage commodity price risk. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will generally record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

Three Months Ended March 31, 2012 compared with Three Months Ended March 31, 2011

Financial and operational highlights for our nonregulated segment for the three months ended March 31, 2012 and 2011 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

	Three Months Ended March 31		
	2012	**2011**	**Change**
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 14,271	$ 19,170	$ (4,899)
Storage and transportation services	3,451	3,522	(71)
Other	996	1,460	(464)
	18,718	24,152	(5,434)
Asset optimization[1]	(10,045)	(686)	(9,359)
Total realized margins	8,673	23,466	(14,793)
Unrealized margins	(12,902)	(3,408)	(9,494)
Gross profit	(4,229)	20,058	(24,287)
Operating expenses, excluding asset impairment	7,185	7,506	(321)
Asset impairment	—	19,282	(19,282)
Operating loss	(11,414)	(6,730)	(4,684)
Miscellaneous income	567	306	261
Interest charges	839	306	533
Loss before income taxes	(11,686)	(6,730)	(4,956)
Income tax benefit	(4,675)	(2,590)	(2,085)
Net loss	$ (7,011)	$ (4,140)	$ (2,871)
Gross nonregulated delivered gas sales volumes — MMcf	111,656	127,377	(15,721)
Consolidated nonregulated delivered gas sales volumes — MMcf	99,844	107,566	(7,722)
Net physical position (Bcf)	38.0	17.7	20.3

(1) Net of storage fees of $4.8 million and $3.6 million.

Results for our nonregulated operations during the second fiscal quarter continue to be adversely influenced by unfavorable natural gas market conditions. Historically high natural gas storage levels caused by strong domestic natural gas production coupled with lower demand driven by an unseasonably warm 2011-2012 winter heating season caused natural gas prices to remain relatively low during our fiscal second quarter. As a result, we continue to experience compressed spot to forward spread values and basis differentials. Additionally, we experienced a quarter-over-quarter decrease in sales volumes due to the relatively warm weather.

We anticipate natural gas storage levels will remain high for an extended period of time. Therefore, we anticipate that basis differentials will remain compressed, which will limit arbitrage and sales opportunities from buying gas in one location and delivering gas into another location. Additionally, we expect gas prices will remain relatively low with lower spot to forward spread volatility relative to recent years. Accordingly, although we anticipate continuing to profit on a fiscal-year basis from our nonregulated activities, we anticipate per-unit margins from our delivered gas activities and margins earned from our asset optimization activities will be lower than in previous years for the foreseeable future.

Realized margins for gas delivery, storage and transportation services and other services were $18.7 million during the three months ended March 31, 2012 compared with $24.2 million for the prior-year quarter. The decrease reflects the following:

- A seven percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather, which reduced sales to utility, municipal and other weather-sensitive customers.
- A decrease in gas delivery per-unit margins from $0.15/Mcf in the prior-year quarter to $0.13/Mcf in the current-year quarter primarily due to lower basis differentials resulting from increased natural gas supply. The decrease in basis differentials was partially offset by increased fees earned from certain transportation arrangements and the receipt of a one-time refund of transportation demand fees from one of our transporters.

Asset optimization margins decreased $9.4 million from the prior-year quarter. In the current year quarter, AEH continued to take advantage of falling natural gas prices by purchasing and injecting a net 8.9 Bcf into storage and capturing incremental physical to forward spread values that should be realized primarily in the third and fourth quarter of fiscal 2012. As a result of this decision and falling prices, we realized significantly higher losses on the settlement of financial instruments used to hedge our natural gas purchases. Additionally, AEH experienced increased storage fees associated with increased park and loan activity.

The $9.5 million decrease in unrealized margins primarily reflects the impact of falling prices on our physical inventory as this hedged inventory is marked to market.

Operating expenses, excluding asset impairment, decreased $0.3 million primarily due to lower employee-related expenses. In the prior-year quarter, an asset impairment charge of $19.3 million was recorded related to our investment in Fort Necessity, which resulted in a write-off of substantially all of our investment in the project.

Six Months Ended March 31, 2012 compared with Six Months Ended March 31, 2011

Financial and operational highlights for our natural gas marketing segment for the six months ended March 31, 2012 and 2011 are presented below.

	Six Months Ended March 31		
	2012	2011	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 25,384	$ 35,211	$ (9,827)
Storage and transportation services	6,640	6,871	(231)
Other	2,013	2,779	(766)
	34,037	44,861	(10,824)
Asset optimization(1)	(31,639)	3,279	(34,918)
Total realized margins	2,398	48,140	(45,742)
Unrealized margins	8,778	(2,904)	11,682
Gross profit	11,176	45,236	(34,060)
Operating expenses, excluding asset impairment	14,904	20,841	(5,937)
Asset impairment	—	19,282	(19,282)
Operating income (loss)	(3,728)	5,113	(8,841)
Miscellaneous income	603	596	7
Interest charges	1,091	1,476	(385)
Income (loss) before income taxes	(4,216)	4,233	(8,449)
Income tax expense (benefit)	(1,674)	1,796	(3,470)
Net income (loss)	$ (2,542)	$ 2,437	$ (4,979)
Gross nonregulated delivered gas sales volumes — MMcf	218,118	235,089	(16,971)
Consolidated nonregulated delivered gas sales volumes — MMcf	190,714	202,104	(11,390)
Net physical position (Bcf)	38.0	17.7	20.3

(1) Net of storage fees of $9.5 million and $6.9 million.

Realized margins for gas delivery, storage and transportation services and other services were $34.0 million during the six months ended March 31, 2012 compared with $44.9 million for the prior-year period. The decrease reflects the following:

- A six percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather, which reduced sales to utility, municipal and other weather-sensitive customers.
- A decrease in gas delivery per-unit margins from $0.15/Mcf in the prior-year quarter to $0.12/Mcf in the current-year quarter primarily due to lower basis differentials resulting from increased natural gas supply. The decrease in basis differentials was partially offset by increased fees earned from certain transportation arrangements and the receipt of a one-time refund of transportation demand fees from one of our transporters.

Asset optimization margins decreased $34.9 million from the prior-year period. The period-over-period decrease primarily reflects AEH's decision to take advantage of falling natural prices by purchasing and injecting a net 24.6 Bcf into storage and capturing incremental physical to forward spread values that should be realized primarily in the third and fourth quarter of fiscal 2012. As a result of this decision and falling prices, we realized significantly higher losses on the settlement of financial instruments used to hedge our natural gas purchases. Additionally, AEH experienced increased storage fees associated with increased park and loan activity. Finally, AEH incurred a $1.7 million charge in the first fiscal quarter to write-down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

Unrealized margins increased $11.7 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses, excluding asset impairment decreased $5.9 million primarily due to lower employee-related expenses. Asset impairment includes the aforementioned pre-tax impairment charge recorded in the prior-year period related to the write-off of substantially all of the Fort Necessity project.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require.

We intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2012.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, prices for our products and services, demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the six months ended March 31, 2012 and 2011 are presented below.

	Six Months Ended March 31		
	2012	2011	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 360,723	$ 438,471	$ (77,748)
Investing activities	(315,001)	(248,198)	(66,803)
Financing activities	(130,101)	(168,979)	38,878
Change in cash and cash equivalents	(84,379)	21,294	(105,673)
Cash and cash equivalents at beginning of period	131,419	131,952	(533)
Cash and cash equivalents at end of period	$ 47,040	$ 153,246	$(106,206)

Cash flows from operating activities

Period-over-period changes in our operating cash flows are primarily attributable to changes in net income and working capital changes, particularly within our natural gas distribution segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the six months ended March 31, 2012, we generated operating cash flow of $360.7 million from operating activities compared with $438.5 million for the six months ended March 31, 2011. The $77.7 million decrease in operating cash flows primarily reflects the effect of purchasing natural gas and injecting it into storage in our nonregulated operations in order to capture incremental value anticipated to be realized in the third and fourth quarter of fiscal 2012, combined with $43.3 million in contributions made to our pension and postretirement plans during the first six months of fiscal 2012 and the timing of customer collections and vendor payments.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund growth projects, our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return on our investment. Currently, rate designs in our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution divisions and our Atmos Pipeline–Texas Division provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

Capital expenditures for fiscal 2012 are currently expected to range from $690 million to $710 million. For the six months ended March 31, 2012, capital expenditures were $311.1 million compared with $246.7 million for the six months ended March 31, 2011. The $64.4 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and other infrastructure replacement projects in our Mid-Tex, West Texas and Kentucky service areas, the development of new customer billing and information systems for our natural gas distribution segment and increased capital spending to increase the capacity on our Atmos Pipeline — Texas system.

Cash flows from financing activities

For the six months ended March 31, 2012, our financing activities used $130.1 million of cash compared with $169.0 million of cash used in the prior-year period, primarily due to lower cash outflows associated with repayment of our short-term and long-term debt instruments, as follows:

- $80.0 million for short-term debt repayments. In the current-year period, $48.9 million of short-term debt was repaid, compared with $128.9 million in the prior-year period.
- $7.7 million for scheduled long-term debt repayments. In the current-year period, $2.4 million of long-term debt was repaid, compared with $10.1 million in the prior-year period.

The lower repayment activity was partially offset by:

- $27.8 million less cash received related to the unwinding of two Treasury locks in the prior year.
- $12.5 million additional cash used to repurchase common stock as part of our share buyback program.
- $7.4 million less cash received from proceeds related to the issuance of common stock.

The following table summarizes our share issuances for the six months ended March 31, 2012 and 2011.

	Six Months Ended March 31	
	2012	2011
Shares issued:		
1998 Long-Term Incentive Plan	219,712	663,555
Outside Directors Stock-for-Fee Plan	1,204	1,232
Total shares issued	220,916	664,787

The year-over-year decrease in the number of shares issued primarily reflects the significant number of stock options exercised in the prior year. During the current-year period, we cancelled and retired 99,555 shares attributable to federal withholdings on equity awards and repurchased and retired 387,991 shares through our 2011 share repurchase program described in Note 7.

As of September 30, 2011, we were authorized to grant awards for up to a maximum of 6.5 million shares of common stock under our 1998 Long-Term Incentive Plan (LTIP). In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. As of March 31, 2012, the amount available to us under our credit facilities, net of outstanding letters of credit, was $687.2 million.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At March 31, 2012, $900 million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our regulated and nonregulated businesses and the regulatory structures that govern our rates in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). As of March 31, 2012, all three ratings agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa1	A-
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of March 31, 2012. Our debt covenants are described in greater detail in Note 6 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2012, September 30, 2011 and March 31, 2011:

	March 31, 2012		September 30, 2011		March 31, 2011	
	(In thousands, except percentages)					
Short-term debt	$ 173,996	3.7%	$ 206,396	4.4%	$ —	—
Long-term debt	2,206,344	46.5%	2,208,551	47.3%	2,159,757	47.6%
Shareholders' equity	2,360,712	49.8%	2,255,421	48.3%	2,373,979	52.4%
Total	$4,741,052	100.0%	$4,670,368	100.0%	$4,533,736	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 50.2 percent at March 31, 2012, 51.7 percent at September 30, 2011 and 47.6 percent at March 31, 2011. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 9 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2012.

Risk Management Activities

We conduct risk management activities through our natural gas distribution and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases.

In our nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and six months ended March 31, 2012 and 2011:

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
	(In thousands)			
Fair value of contracts at beginning of period	$(85,829)	$ 26,806	$(79,277)	$ (49,600)
Contracts realized/settled	(13,807)	(18,064)	(31,537)	(51,045)
Fair value of new contracts	176	540	(377)	1,071
Other changes in value	51,928	21,251	63,659	130,107
Fair value of contracts at end of period	$(47,532)	$ 30,533	$(47,532)	$ 30,533

The fair value of our natural gas distribution segment's financial instruments at March 31, 2012 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2012				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(47,531)	$ (1)	$—	$—	$(47,532)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(47,531)	$ (1)	$—	$—	$(47,532)

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and six months ended March 31, 2012 and 2011:

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
	(In thousands)			
Fair value of contracts at beginning of period	$(15,263)	$(10,681)	$(25,050)	$(12,374)
Contracts realized/settled	13,779	(1,009)	31,228	(75)
Fair value of new contracts	—	—	—	—
Other changes in value	(1,090)	(1,252)	(8,752)	(493)
Fair value of contracts at end of period	(2,574)	(12,942)	(2,574)	(12,942)
Netting of cash collateral	5,696	17,053	5,696	17,053
Cash collateral and fair value of contracts at period end	$ 3,122	$ 4,111	$ 3,122	$ 4,111

The fair value of our nonregulated segment's financial instruments at March 31, 2012 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2012				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(8,115)	$5,563	$(22)	$—	$(2,574)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(8,115)	$5,563	$(22)	$—	$(2,574)

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2012 and 2011, our total net periodic pension and other benefits costs were $34.6 million and $28.8 million. A substantial portion of those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2012 costs were determined using a September 30, 2011 measurement date. As of September 30, 2011, interest and corporate bond rates utilized to determine our discount rates were lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. We reduced the expected return on our pension plan assets to 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Accordingly, our fiscal 2012 pension and postretirement medical costs for the six months ended March 31, 2012 were higher than the prior-year period.

The amounts we fund our defined benefit plans with are determined in accordance with the PPA and are influenced by the discount rate and funded position of the plans when the funding requirements are determined on January 1 of each year. We completed our valuation for fiscal 2012 during the second fiscal quarter and as a result of lower asset returns and a year-over-year 92 basis point decline in the discount rate used to value our qualified pension liabilities, we were required to contribute $23.0 million to the plans. During the six months ended March 31, 2012, we contributed $34.2 million to our defined benefit plans and we anticipate contributing an additional $12.4 million during the remainder of the fiscal year. Additionally, we contributed $9.1 million to our postretirement medical plans during the six months ended March 31, 2012 and anticipate contributing between $10 million and $15 million to these plans during the remainder of the fiscal year. We believe our cash flows from operations are sufficient to fund these contributions.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts will be determined by actual investment returns, changes in interest rates, values of assets in the plan and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three and six month periods ended March 31, 2012 and 2011.

Natural Gas Distribution Sales and Statistical Data — Continuing Operations

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
METERS IN SERVICE, end of period				
Residential	2,862,546	2,856,181	2,862,546	2,856,181
Commercial	261,449	260,010	261,449	260,010
Industrial	2,281	2,323	2,281	2,323
Public authority and other	10,245	10,194	10,245	10,194
Total meters	3,136,521	3,128,708	3,136,521	3,128,708
INVENTORY STORAGE BALANCE — Bcf	33.2	28.2	33.2	28.2
SALES VOLUMES — MMcf [(2)]				
Gas sales volumes				
Residential	63,362	82,920	113,602	133,076
Commercial	31,667	39,456	58,271	65,485
Industrial	4,697	6,046	10,109	11,192
Public authority and other	3,443	4,095	6,077	6,901
Total gas sales volumes	103,169	132,517	188,059	216,654
Transportation volumes	38,069	38,571	72,036	71,788
Total throughput	141,238	171,088	260,095	288,442
OPERATING REVENUES (000's)[(2)]				
Gas sales revenues				
Residential	$ 589,108	$ 702,858	$1,026,617	$1,146,497
Commercial	229,204	285,680	418,892	474,945
Industrial	25,148	34,427	51,855	63,116
Public authority and other	21,749	27,546	39,243	46,083
Total gas sales revenues	865,209	1,050,511	1,536,607	1,730,641
Transportation revenues	15,867	17,727	30,729	33,418
Other gas revenues	7,932	9,176	14,964	16,817
Total operating revenues	$ 889,008	$1,077,414	$1,582,300	$1,780,876
Average transportation revenue per Mcf[(1)]	$ 0.42	$ 0.46	$ 0.43	$ 0.47
Average cost of gas per Mcf sold[(1)]	$ 4.94	$ 5.28	$ 4.87	$ 5.14

See footnote following these tables.

Natural Gas Distribution Sales and Statistical Data — Discontinued Operations

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
Meters in service, end of period	83,524	84,323	83,524	84,323
Inventory storage balance — Bcf	2.2	1.9	2.2	1.9
Sales volumes — MMcf				
Total gas sales volumes	3,094	4,321	5,523	6,974
Transportation volumes	1,754	2,085	3,351	3,621
Total throughput	4,848	6,406	8,874	10,595
Operating revenues (000's)	$26,374	$35,790	$49,825	$59,523

Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2012	2011	2012	2011
CUSTOMERS, end of period				
Industrial	781	753	781	753
Municipal	139	62	139	62
Other	444	513	444	513
Total	1,364	1,328	1,364	1,328
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	49.0	23.3	49.0	23.3
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf(2)	176,361	174,471	337,190	327,649
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf(2)	111,656	127,377	218,118	235,089
OPERATING REVENUES (000's)(2)				
Regulated transmission and storage	$ 58,037	$ 54,976	$114,796	$ 103,983
Nonregulated	370,763	583,531	814,939	1,059,171
Total operating revenues	$428,800	$638,507	$929,735	$1,163,154

Notes to preceding tables:

(1) Statistics are shown on a consolidated basis.

(2) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the unaudited condensed consolidated financial statements.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk*

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the six months ended March 31, 2012, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of March 31, 2012 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of the fiscal year ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the six months ended March 31, 2012, except as noted in Note 9 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds*

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company. We did not repurchase any shares during the second quarter of fiscal 2012. At March 31, 2012, there were 4,612,009 shares of repurchase authority remaining under the program.

Item 6. *Exhibits*

A list of exhibits required by Item 601 of Regulation S-K and filed as part of this report is set forth in the Exhibits Index, which immediately precedes such exhibits.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ FRED E. MEISENHEIMER

Fred E. Meisenheimer
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: May 3, 2012

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	
101.INS	XBRL Instance Document **	
101.SCH	XBRL Taxonomy Extension Schema **	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase **	
101.DEF	XBRL Taxonomy Extension Definition Linkbase **	
101.LAB	XBRL Taxonomy Extension Labels Linkbase **	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase **	

* These certifications, which were made pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Quarterly Report on Form 10-Q, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

CONSOLIDATED EDISON INC

10-Q

Quarterly report pursuant to sections 13 or 15(d)
Filed on 05/03/2012
Filed Period 03/31/2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

☒ Quarterly Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2012

OR

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from __________ to __________

Commission File Number	Exact name of registrant as specified in its charter and principal office address and telephone number	State of Incorporation	I.R.S. Employer ID. Number
1-14514	**Consolidated Edison, Inc.** 4 Irving Place, New York, New York 10003 (212) 460-4600	New York	13-3965100
1-1217	**Consolidated Edison Company of New York, Inc.** 4 Irving Place, New York, New York 10003 (212) 460-4600	New York	13-5009340

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Consolidated Edison, Inc. (Con Edison)	Yes ☒	No ☐
Consolidated Edison of New York, Inc. (CECONY)	Yes ☒	No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Con Edison	Yes ☒	No ☐
CECONY	Yes ☒	No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Con Edison

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐

CECONY

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Con Edison	Yes ☐	No ☒
CECONY	Yes ☐	No ☒

As of April 27, 2012, Con Edison had outstanding 292,904,261 Common Shares ($.10 par value). All of the outstanding common equity of CECONY is held by Con Edison.

Filing Format

This Quarterly Report on Form 10-Q is a combined report being filed separately by two different registrants: Consolidated Edison, Inc. (Con Edison) and Consolidated Edison Company of New York, Inc. (CECONY). CECONY is a subsidiary of Con Edison and, as such, the information in this report about CECONY also applies to Con Edison. As used in this report, the term the "Companies" refers to Con Edison and CECONY. However, CECONY makes no representation as to the information contained in this report relating to Con Edison or the subsidiaries of Con Edison other than itself.

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Glossary of Terms

The following is a glossary of frequently used abbreviations or acronyms that are used in the Companies' SEC reports:

Con Edison Companies

Con Edison	Consolidated Edison, Inc.
CECONY	Consolidated Edison Company of New York, Inc.
Con Edison Development	Consolidated Edison Development, Inc.
Con Edison Energy	Consolidated Edison Energy, Inc.
Con Edison Solutions	Consolidated Edison Solutions, Inc.
O&R	Orange and Rockland Utilities, Inc.
Pike	Pike County Light & Power Company
RECO	Rockland Electric Company
The Companies	Con Edison and CECONY
The Utilities	CECONY and O&R

Regulatory Agencies, Government Agencies, and Quasi-governmental Not-for-Profits

EPA	U. S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
ISO-NE	ISO New England Inc.
NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSAG	New York State Attorney General
NYSDEC	New York State Department of Environmental Conservation
NYSERDA	New York State Energy Research and Development Authority
NYSPSC	New York State Public Service Commission
NYSRC	New York State Reliability Council, LLC
PAPUC	Pennsylvania Public Utility Commission
PJM	PJM Interconnection LLC
SEC	U.S. Securities and Exchange Commission

Accounting

ABO	Accumulated Benefit Obligation
ASU	Accounting Standards Update
FASB	Financial Accounting Standards Board
LILO	Lease In/Lease Out
OCI	Other Comprehensive Income
SFAS	Statement of Financial Accounting Standards
VIE	Variable interest entity

Environmental

CO_2	Carbon dioxide
GHG	Greenhouse gases
MGP Sites	Manufactured gas plant sites
PCBs	Polychlorinated biphenyls
PRP	Potentially responsible party
SO_2	Sulfur dioxide
Superfund	Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 and similar state statutes

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Units of Measure

dths	Dekatherms
kV	Kilovolt
kWh	Kilowatt-hour
mdths	Thousand dekatherms
MMlbs	Million pounds
MVA	Megavolt ampere
MW	Megawatt or thousand kilowatts
MWH	Megawatt hour

Other

AFDC	Allowance for funds used during construction
COSO	Committee of Sponsoring Organizations of the Treadway Commission
EMF	Electric and magnetic fields
ERRP	East River Repowering Project
Fitch	Fitch Ratings
First Quarter Form 10-Q	The Companies' combined Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012
Form 10-K	The Companies' combined Annual Report on Form 10-K for the year ended December 31, 2011
LTIP	Long Term Incentive Plan
Moody's	Moody's Investors Service
S&P	Standard & Poor's Financial Services LLC
VaR	Value-at-Risk

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FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements intended to qualify for the safe-harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are statements of future expectation and not facts. Words such as "expects," "estimates," "anticipates," "intends," "believes," "plans," "will" and similar expressions identify forward-looking statements. Forward-looking statements are based on information available at the time the statements are made, and accordingly speak only as of that time. Actual results or developments might differ materially from those included in the forward-looking statements because of various risks, including:

- the failure to operate energy facilities safely and reliably could adversely affect the Companies;
- the failure to properly complete construction projects could adversely affect the Companies;
- the failure of processes and systems and the performance of employees and contractors could adversely affect the Companies;
- the Companies are extensively regulated and are subject to penalties;
- the Utilities' rate plans may not provide a reasonable return;
- the Companies may be adversely affected by changes to the Utilities' rate plans;
- the Companies are exposed to risks from the environmental consequences of their operations;
- a disruption in the wholesale energy markets or failure by an energy supplier could adversely affect the Companies;
- the Companies have substantial unfunded pension and other postretirement benefit liabilities;
- Con Edison's ability to pay dividends or interest depends on dividends from its subsidiaries;
- the Companies require access to capital markets to satisfy funding requirements;
- the Internal Revenue Service has disallowed substantial tax deductions taken by the company;
- a cyber attack could adversely affect the Companies; and
- the Companies also face other risks that are beyond their control.

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Consolidated Edison, Inc.
CONSOLIDATED INCOME STATEMENT (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(Millions of Dollars/ Except Share Data)	
OPERATING REVENUES		
Electric	$ 1,862	$ 1,869
Gas	645	755
Steam	263	325
Non-utility	308	400
TOTAL OPERATING REVENUES	3,078	3,349
OPERATING EXPENSES		
Purchased power	781	865
Fuel	108	176
Gas purchased for resale	196	308
Operations and maintenance	749	698
Depreciation and amortization	233	218
Taxes, other than income taxes	450	458
TOTAL OPERATING EXPENSES	2,517	2,723
OPERATING INCOME	561	626
OTHER INCOME (DEDUCTIONS)		
Investment and other income	7	9
Allowance for equity funds used during construction	—	4
Other deductions	(4)	(4)
TOTAL OTHER INCOME (DEDUCTIONS)	3	9
INCOME BEFORE INTEREST AND INCOME TAX EXPENSE	564	635
INTEREST EXPENSE		
Interest on long-term debt	145	147
Other interest	5	7
Allowance for borrowed funds used during construction	—	(2)
NET INTEREST EXPENSE	150	152
INCOME BEFORE INCOME TAX EXPENSE	414	483
INCOME TAX EXPENSE	134	169
NET INCOME	280	314
Preferred stock dividend requirements of subsidiary	(3)	(3)
NET INCOME FOR COMMON STOCK	$ 277	$ 311
Net income for common stock per common share – basic	$ 0.95	$ 1.07
Net income for common stock per common share – diluted	$ 0.94	$ 1.06
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 0.605	$ 0.600
AVERAGE NUMBER OF SHARES OUTSTANDING – BASIC (IN MILLIONS)	292.9	292.0
AVERAGE NUMBER OF SHARES OUTSTANDING – DILUTED (IN MILLIONS)	294.5	293.6

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison, Inc.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(Millions of Dollars)	
NET INCOME	$ 280	$ 314
OTHER COMPREHENSIVE INCOME/(LOSS), NET OF TAXES		
Pension plan liability adjustments, net of $5 and $2 taxes in 2012 and 2011, respectively	7	3
TOTAL OTHER COMPREHENSIVE INCOME/(LOSS), NET OF TAXES	7	3
COMPREHENSIVE INCOME	$ 287	$ 317
Preferred stock dividend requirements of subsidiary	(3)	(3)
COMPREHENSIVE INCOME FOR COMMON STOCK	$ 284	$ 314

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison, Inc.
CONSOLIDATED STATEMENT OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(Millions of Dollars)	
OPERATING ACTIVITIES		
Net Income	$ 280	$ 314
PRINCIPAL NON-CASH CHARGES/(CREDITS) TO INCOME		
Depreciation and amortization	233	218
Deferred income taxes	68	232
Rate case amortization and accruals	31	19
Common equity component of allowance for funds used during construction	—	(4)
Net derivative losses/(gains)	31	(37)
Other non-cash items (net)	64	(17)
CHANGES IN ASSETS AND LIABILITIES		
Accounts receivable – customers, less allowance for uncollectibles	54	(5)
Materials and supplies, including fuel oil and gas in storage	31	103
Other receivables and other current assets	(2)	66
Prepayments	(286)	(217)
Accounts payable	(78)	(154)
Pensions and retiree benefits obligations	253	259
Pensions and retiree benefits contribution	(184)	(491)
Accrued taxes	41	(20)
Accrued interest	52	51
Deferred charges, noncurrent assets and other regulatory assets	(255)	(19)
Deferred credits and other regulatory liabilities	117	67
Other assets	—	(1)
Other liabilities	(48)	(2)
NET CASH FLOWS FROM OPERATING ACTIVITIES	402	362
INVESTING ACTIVITIES		
Utility construction expenditures	(471)	(394)
Cost of removal less salvage	(43)	(39)
Non-utility construction expenditures	(9)	(23)
Proceeds from investment tax credits and grants related to renewable energy investments	6	—
Net investment in Pilesgrove solar project and other	27	—
Loan to affiliate	—	(40)
NET CASH FLOWS USED IN INVESTING ACTIVITIES	(490)	(496)
FINANCING ACTIVITIES		
Net proceeds from short-term debt	—	464
Retirement of long-term debt	(1)	(1)
Issuance of long-term debt	400	—
Issuance of common shares for stock plans, net of repurchases	(8)	25
Debt issuance costs	(4)	—
Common stock dividends	(175)	(173)
Preferred stock dividends	(3)	(3)
NET CASH FLOWS FROM FINANCING ACTIVITIES	209	312
CASH AND TEMPORARY CASH INVESTMENTS:		
NET CHANGE FOR THE PERIOD	121	178
BALANCE AT BEGINNING OF PERIOD	648	338
BALANCE AT END OF PERIOD	$ 769	$ 516
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid/(refunded) during the period for:		
Interest	$ 89	$ 90
Income taxes	$ —	$ (172)

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison, Inc.
CONSOLIDATED BALANCE SHEET (UNAUDITED)

	March 31, 2012	December 31, 2011
	(Millions of Dollars)	
ASSETS		
CURRENT ASSETS		
Cash and temporary cash investments	$ 769	$ 648
Accounts receivable – customers, less allowance for uncollectible accounts of $87 in 2012 and 2011	1,069	1,123
Accrued unbilled revenue	379	474
Other receivables, less allowance for uncollectible accounts of $10 in 2012 and 2011	249	303
Fuel oil, gas in storage, materials and supplies, at average cost	325	356
Prepayments	431	145
Deferred tax assets – current	285	266
Regulatory assets	192	164
Other current assets	205	159
TOTAL CURRENT ASSETS	3,904	3,638
INVESTMENTS	440	455
UTILITY PLANT, AT ORIGINAL COST		
Electric	21,520	21,105
Gas	4,821	4,727
Steam	2,015	1,983
General	2,093	1,960
TOTAL	30,449	29,775
Less: Accumulated depreciation	6,153	6,051
Net	24,296	23,724
Construction work in progress	920	1,241
NET UTILITY PLANT	25,216	24,965
NON-UTILITY PLANT		
Non-utility property, less accumulated depreciation of $61 and $59 in 2012 and 2011, respectively	98	89
Construction work in progress	39	39
NET PLANT	25,353	25,093
OTHER NONCURRENT ASSETS		
Goodwill	429	429
Intangible assets, less accumulated amortization of $3 in 2012 and 2011	3	3
Regulatory assets	9,276	9,337
Other deferred charges and noncurrent assets	296	259
TOTAL OTHER NONCURRENT ASSETS	10,004	10,028
TOTAL ASSETS	$ 39,701	$ 39,214

The accompanying notes are an integral part of these financial statements.

Consolidated Edison, Inc.
CONSOLIDATED BALANCE SHEET (UNAUDITED)

	March 31, 2012	December 31, 2011
	(Millions of Dollars)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Long-term debt due within one year	$ 1,030	$ 530
Accounts payable	844	955
Customer deposits	306	303
Accrued taxes	229	188
Accrued interest	212	160
Accrued wages	91	91
Fair value of derivative liabilities	198	169
Regulatory liabilities	286	118
Preferred stock redemption	239	—
Other current liabilities	405	473
TOTAL CURRENT LIABILITIES	3,840	2,987
NONCURRENT LIABILITIES		
Obligations under capital leases	2	2
Provision for injuries and damages	158	181
Pensions and retiree benefits	4,605	4,835
Superfund and other environmental costs	537	489
Asset retirement obligations	147	145
Fair value of derivative liabilities	54	48
Other noncurrent liabilities	131	131
TOTAL NONCURRENT LIABILITIES	5,634	5,831
DEFERRED CREDITS AND REGULATORY LIABILITIES		
Deferred income taxes and investment tax credits	7,712	7,563
Regulatory liabilities	846	977
Other deferred credits	83	64
TOTAL DEFERRED CREDITS AND REGULATORY LIABILITIES	8,641	8,604
LONG-TERM DEBT	10,041	10,143
SHAREHOLDERS' EQUITY		
Common shareholders' equity (See Statement of Common Shareholders' Equity)	11,545	11,436
Preferred stock of subsidiary	—	213
TOTAL SHAREHOLDERS' EQUITY	11,545	11,649
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 39,701	$ 39,214

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison, Inc.

CONSOLIDATED STATEMENT OF COMMON SHAREHOLDERS' EQUITY (UNAUDITED)

(Millions of Dollars/Except Share Data)	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Capital Stock Expense	Accumulated Other Comprehensive Income/(Loss)	Total
BALANCE AS OF DECEMBER 31, 2010	291,616,334	$ 31	$ 4,915	$ 7,220	23,210,700	$ (1,001)	$ (64)	$ (40)	$11,061
Net income for common stock				311					311
Common stock dividends				(175)					(175)
Issuance of common shares – dividend reinvestment and employee stock plans	656,049	1	30						31
Other comprehensive income								3	3
BALANCE AS OF MARCH 31, 2011	292,272,383	$ 32	$ 4,945	$ 7,356	23,210,700	$ (1,001)	$ (64)	$ (37)	$11,231
BALANCE AS OF DECEMBER 31, 2011	292,888,521	$ 32	$ 4,991	$ 7,568	23,194,075	$ (1,033)	$ (64)	$ (58)	$11,436
Net income for common stock				277					277
Common stock dividends				(177)					(177)
Issuance of common shares for stock plans, net of repurchases	(7,225)				7,225	(2)			(2)
Preferred stock redemption							4		4
Other comprehensive income								7	7
BALANCE AS OF MARCH 31, 2012	292,881,296	$ 32	$ 4,991	$ 7,668	23,201,300	$ (1,035)	$ (60)	$ (51)	$11,545

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison Company of New York, Inc.
CONSOLIDATED INCOME STATEMENT (UNAUDITED)

	For the Three Month Ended March 31,	
	2012	2011
	(Millions of Dollars)	
OPERATING REVENUES		
Electric	$ 1,735	$ 1,721
Gas	563	663
Steam	263	325
TOTAL OPERATING REVENUES	2,561	2,709
OPERATING EXPENSES		
Purchased power	447	483
Fuel	108	176
Gas purchased for resale	169	263
Operations and maintenance	645	597
Depreciation and amortization	218	204
Taxes, other than income taxes	430	440
TOTAL OPERATING EXPENSES	2,017	2,163
OPERATING INCOME	544	546
OTHER INCOME (DEDUCTIONS)		
Investment and other income	5	5
Allowance for equity funds used during construction	—	3
Other deductions	(3)	(3)
TOTAL OTHER INCOME (DEDUCTIONS)	2	5
INCOME BEFORE INTEREST AND INCOME TAX EXPENSE	546	551
INTEREST EXPENSE		
Interest on long-term debt	131	132
Other interest	5	5
Allowance for borrowed funds used during construction	—	(2)
NET INTEREST EXPENSE	136	135
INCOME BEFORE INCOME TAX EXPENSE	410	416
INCOME TAX EXPENSE	134	145
NET INCOME	276	271
Preferred stock dividend requirements	(3)	(3)
NET INCOME FOR COMMON STOCK	$ 273	$ 268

The accompanying notes are an integral part of these financial statements.

Consolidated Edison Company of New York, Inc.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Month Ended March 31,	
	2012	2011
	(Millions of Dollars)	
NET INCOME	$ 276	$ 271
OTHER COMPREHENSIVE INCOME/(LOSS), NET OF TAXES		
Pension plan liability adjustments, net of $— taxes in 2012 and 2011	—	—
TOTAL OTHER COMPREHENSIVE INCOME/(LOSS), NET OF TAXES	—	—
COMPREHENSIVE INCOME	$ 276	$ 271

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison Company of New York, Inc.
CONSOLIDATED STATEMENT OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(Millions of Dollars)	
OPERATING ACTIVITIES		
Net income	$ 276	$ 271
PRINCIPAL NON-CASH CHARGES/(CREDITS) TO INCOME		
Depreciation and amortization	218	204
Deferred income taxes	66	207
Rate case amortization and accruals	31	19
Common equity component of allowance for funds used during construction	—	(3)
Other non-cash items (net)	15	10
CHANGES IN ASSETS AND LIABILITIES		
Accounts receivable – customers, less allowance for uncollectibles	43	22
Materials and supplies, including fuel oil and gas in storage	22	84
Other receivables and other current assets	16	(77)
Prepayments	(287)	(291)
Accounts payable	(48)	(119)
Pensions and retiree benefits obligations	209	236
Pensions and retiree benefits contribution	(184)	(491)
Accrued taxes	57	(37)
Accrued interest	42	44
Superfund and environmental remediation costs (net)	(1)	—
Deferred charges, noncurrent assets and other regulatory assets	(179)	(63)
Deferred credits and other regulatory liabilities	108	52
Other liabilities	(36)	4
NET CASH FLOWS FROM OPERATING ACTIVITIES	368	72
INVESTING ACTIVITIES		
Utility construction expenditures	(446)	(376)
Cost of removal less salvage	(41)	(37)
NET CASH FLOWS USED IN INVESTING ACTIVITIES	(487)	(413)
FINANCING ACTIVITIES		
Net proceeds from short-term debt	—	464
Issuance of long-term debt	400	—
Debt issuance costs	(4)	—
Dividend to parent	(171)	(170)
Preferred stock dividends	(3)	(3)
NET CASH FLOWS USED IN FINANCING ACTIVITIES	222	291
CASH AND TEMPORARY CASH INVESTMENTS:		
NET CHANGE FOR THE PERIOD	103	(50)
BALANCE AT BEGINNING OF PERIOD	372	78
BALANCE AT END OF PERIOD	$ 475	$ 28
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid/(refunded) during the period for:		
Interest	$ 83	$ 82
Income taxes	$ (20)	$ 35

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison Company of New York, Inc.
CONSOLIDATED BALANCE SHEET (UNAUDITED)

	March 31, 2012	December 31, 2011
	(Millions of Dollars)	
ASSETS		
CURRENT ASSETS		
Cash and temporary cash investments	$ 475	$ 372
Accounts receivable – customers, less allowance for uncollectible accounts of $79 in 2012 and 2011	934	977
Other receivables, less allowance for uncollectible accounts of $9 in 2012 and 2011	110	102
Accrued unbilled revenue	285	366
Accounts receivable from affiliated companies	36	54
Fuel oil, gas in storage, materials and supplies, at average cost	286	308
Prepayments	372	85
Regulatory assets	159	140
Deferred tax assets – current	170	157
Other current assets	97	100
TOTAL CURRENT ASSETS	2,924	2,661
INVESTMENTS	188	177
UTILITY PLANT AT ORIGINAL COST		
Electric	20,284	19,886
Gas	4,285	4,200
Steam	2,015	1,983
General	1,917	1,785
TOTAL	28,501	27,854
Less: Accumulated depreciation	5,616	5,523
Net	22,885	22,331
Construction work in progress	853	1,165
NET UTILITY PLANT	23,738	23,496
NON-UTILITY PROPERTY		
Non-utility property, less accumulated depreciation of $24 in 2012 and 2011	6	6
NET PLANT	23,744	23,502
OTHER NONCURRENT ASSETS		
Regulatory assets	8,645	8,661
Other deferred charges and noncurrent assets	254	217
TOTAL OTHER NONCURRENT ASSETS	8,899	8,878
TOTAL ASSETS	$ 35,755	$ 35,218

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison Company of New York, Inc.
CONSOLIDATED BALANCE SHEET (UNAUDITED)

	March 31, 2012	December 31, 2011
	(Millions of Dollars)	
LIABILITIES AND SHAREHOLDER'S EQUITY		
CURRENT LIABILITIES		
Long-term debt due within one year	$ 1,024	$ 525
Accounts payable	690	774
Accounts payable to affiliated companies	17	16
Customer deposits	293	290
Accrued taxes	17	32
Accrued taxes to affiliated companies	198	126
Accrued interest	175	133
Accrued wages	82	81
Fair value of derivative liabilities	112	98
Regulatory liabilities	242	79
Preferred stock redemption	239	—
Other current liabilities	338	396
TOTAL CURRENT LIABILITIES	3,427	2,550
NONCURRENT LIABILITIES		
Obligations under capital leases	2	2
Provision for injuries and damages	151	173
Pensions and retiree benefits	4,142	4,337
Superfund and other environmental costs	421	373
Asset retirement obligations	147	145
Fair value of derivative liabilities	31	24
Other noncurrent liabilities	121	120
TOTAL NONCURRENT LIABILITIES	5,015	5,174
DEFERRED CREDITS AND REGULATORY LIABILITIES		
Deferred income taxes and investment tax credits	7,059	6,921
Regulatory liabilities	730	861
Other deferred credits	81	61
TOTAL DEFERRED CREDITS AND REGULATORY LIABILITIES	7,870	7,843
LONG-TERM DEBT	9,119	9,220
SHAREHOLDER'S EQUITY		
Common shareholder's equity (See Statement of Common Shareholder's Equity)	10,324	10,218
Preferred stock	—	213
TOTAL SHAREHOLDER'S EQUITY	10,324	10,431
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 35,755	$ 35,218

The accompanying notes are an integral part of these financial statements.

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Consolidated Edison Company of New York, Inc.
CONSOLIDATED STATEMENT OF COMMON SHAREHOLDER'S EQUITY (UNAUDITED)

(Millions of Dollars/Except Share Data)	Common Stock Shares	Common Stock Amount	Additional Paid- In Capital	Retained Earnings	Repurchased Con Edison Stock	Capital Stock Expense	Accumulated Other Comprehensive Income/(Loss)	Total
BALANCE AS OF DECEMBER 31, 2010	235,488,094	$ 589	$ 4,234	$ 6,132	$ (962)	$ (64)	$ (6)	$ 9,923
Net income				271				271
Common stock dividend to parent				(170)				(170)
Cumulative preferred dividends				(3)				(3)
Other comprehensive income							—	—
BALANCE AS OF MARCH 31, 2011	235,488,094	$ 589	$ 4,234	$ 6,230	$ (962)	$ (64)	$ (6)	$ 10,021
BALANCE AS OF DECEMBER 31, 2011	235,488,094	$ 589	$ 4,234	$ 6,429	$ (962)	$ (64)	$ (8)	$ 10,218
Net income				276				276
Common stock dividend to parent				(171)				(171)
Cumulative preferred dividends				(3)				(3)
Preferred stock redemption						4		4
Other comprehensive income							—	—
BALANCE AS OF MARCH 31, 2012	235,488,094	$ 589	$ 4,234	$ 6,531	$ (962)	$ (60)	$ (8)	$ 10,324

The accompanying notes are an integral part of these financial statements.

NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)

General

These combined notes accompany and form an integral part of the separate consolidated financial statements of each of the two separate registrants: Consolidated Edison, Inc. and its subsidiaries (Con Edison) and Consolidated Edison Company of New York, Inc. and its subsidiaries (CECONY). CECONY is a subsidiary of Con Edison and as such its financial condition and results of operations and cash flows, which are presented separately in the CECONY consolidated financial statements, are also consolidated, along with those of Con Edison's other utility subsidiary, Orange and Rockland Utilities, Inc. (O&R), and Con Edison's competitive energy businesses (discussed below) in Con Edison's consolidated financial statements. The term "Utilities" is used in these notes to refer to CECONY and O&R.

As used in these notes, the term "Companies" refers to Con Edison and CECONY and, except as otherwise noted, the information in these combined notes relates to each of the Companies. However, CECONY makes no representation as to information relating to Con Edison or the subsidiaries of Con Edison other than itself.

The separate interim consolidated financial statements of each of the Companies are unaudited but, in the opinion of their respective managements, reflect all adjustments (which include only normally recurring adjustments) necessary for a fair presentation of the results for the interim periods presented. The Companies' separate interim consolidated financial statements should be read together with their separate audited financial statements (including the combined notes thereto) included in Item 8 of their combined Annual Report on Form 10-K for the year ended December 31, 2011. Certain prior period amounts have been reclassified to conform to the current period presentation.

Con Edison has two regulated utility subsidiaries: CECONY and O&R. CECONY provides electric service and gas service in New York City and Westchester County. The company also provides steam service in parts of Manhattan. O&R, along with its regulated utility subsidiaries, provides electric service in southeastern New York and adjacent areas of northern New Jersey and eastern Pennsylvania and gas service in southeastern New York and adjacent areas of eastern Pennsylvania. Con Edison has the following competitive energy businesses: Consolidated Edison Solutions, Inc. (Con Edison Solutions), a retail energy services company that sells electricity and also offers energy-related services; Consolidated Edison Energy, Inc. (Con Edison Energy), a wholesale energy supply and services company; and Consolidated Edison Development, Inc. (Con Edison Development), a company that develops and participates in infrastructure projects.

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Note A — Summary of Significant Accounting Policies

Earnings Per Common Share

For the three months ended March 31, 2012 and 2011, basic and diluted EPS for Con Edison are calculated as follows:

(Millions of Dollars, except per share amounts/Shares in Millions)	2012	2011
Net income for common stock	$ 277	$ 311
Weighted average common shares outstanding – Basic	292.9	292.0
Add: Incremental shares attributable to effect of potentially dilutive securities	1.6	1.6
Adjusted weighted average common shares outstanding – Diluted	294.5	293.6
Net income for common stock per common share – basic	$ 0.95	$ 1.07
Net income for common stock per common share – diluted	$ 0.94	$ 1.06

Note B — Regulatory Matters

Rate Agreements

CECONY — Electric

In March 2012, the NYSPSC issued an order requiring that the $134 million surcharge that was to have been collected from customers during the rate year ending March 2013 instead be offset using certain CECONY regulatory liabilities that would have otherwise been refundable to or applied for the benefit of customers after the rate year.

O&R — Electric

On February 24, 2012, O&R, the staff of the NYSPSC and the Utility Intervention Unit of New York State's Division of Consumer Protection entered into a Joint Proposal with respect to the Company's rates for electric delivery service rendered in New York. The Joint Proposal, which is subject to NYSPSC approval, covers the three-year period from July 2012 through June 2015. The Joint Proposal provides for electric base rate increases of $19.4 million, $8.8 million and $15.2 million, effective July 2012, 2013 and 2014, respectively, which can be implemented, at the NYSPSC's option, with increases of $15.2 million effective July 2012 and 2013 and an increase of $13.1 million, together with a surcharge of $2.1 million, effective July 2014. The Joint Proposal reflects the following major items:

- a weighted average cost of capital of 7.61 percent, 7.65 percent and 7.48 percent for the rate years ending June 30, 2013, 2014 and 2015, respectively, reflecting:
  - a return on common equity of 9.4 percent, 9.5 percent and 9.6 percent for the rate years ending June 30, 2013, 2014 and 2015, respectively;
  - cost of long-term debt of 6.07 percent for each of the rate years ending June 30, 2013 and 2014 and 5.64 percent for the rate year ending June 30 2015;
  - common equity ratio of 48 percent for each of the rate years ending June 30, 2013, 2014 and 2015; and
  - average rate base of $671 million, $708 million and $759 million for the rate years ending June 30, 2013, 2014 and 2015, respectively;
- sharing with electric customers of any actual earnings, excluding the effects of any penalties and certain other items, above specified percentage returns on common equity (based on the actual average common equity ratio, subject to a 50 percent maximum):
  - the company will allocate to customers the revenue requirement equivalent of 50 percent, 75 percent and 90 percent of any such earnings for each rate year in excess of 80 basis points, 180 basis points and 280 basis points, respectively, above the return on common equity for that rate year indicated above; and
  - the earnings sharing allocation between the company and customers will be done on a cumulative basis at the end of rate year three;
- continuation of a revenue decoupling mechanism;

- continuation of a provision which defers as a regulatory liability for the benefit of customers or, subject to certain limitations, a regulatory asset for recovery from customers, as the case may be, the revenue requirement impact of the amount by which actual average net utility plant for each rate year is different than the average net utility plant reflected in rates ($678 million, $704 million and $753 million for the rate years ending June 30, 2013, 2014 and 2015, respectively);
- continuation of the rate provisions pursuant to which the company recovers its purchased power costs from customers;
- continuation of rate provisions under which pension and other post-retirement benefit expenses, environmental remediation expenses, tax-exempt debt costs and certain other expenses are reconciled to amounts for those expenses reflected in rates;
- provisions under which property taxes are reconciled to amounts reflected in rates; and
- continuation of provisions for potential operations penalties of up to $3 million annually if certain customer service and system reliability performance targets are not met.

Other Regulatory Matters

In February 2009, the NYSPSC commenced a proceeding to examine the prudence of certain CECONY expenditures (see "Investigations of Vendor Payments" in Note H). Pursuant to NYSPSC orders, a portion of the company's revenues (currently, $249 million, $32 million and $6 million on an annual basis for electric, gas and steam service, respectively) is being collected subject to potential refund to customers. At March 31, 2012, the company had collected an estimated $887 million from customers subject to potential refund in connection with this proceeding. In October 2010, a NYSPSC consultant reported its $21 million provisional assessment, which the company has disputed, of potential overcharges for construction work. The potential overcharges related to transactions that involved certain employees who were arrested and a contractor that performed work for the company. The NYSPSC's consultant is expected to continue to review the company's expenditures. At March 31, 2012, the company had an $8 million regulatory liability relating to this matter. The company is unable to estimate the amount, if any, by which any refund required by the NYSPSC may exceed this regulatory liability.

In February 2011, the NYSPSC initiated a proceeding to examine the existing mechanisms pursuant to which utilities recover site investigation and remediation costs and possible alternatives. See Note G.

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Regulatory Assets and Liabilities

Regulatory assets and liabilities at March 31, 2012 and December 31, 2011 were comprised of the following items:

	Con Edison		CECONY	
(Millions of Dollars)	2012	2011	2012	2011
Regulatory assets				
Unrecognized pension and other postretirement costs	$ 5,594	$ 5,852	$ 5,337	$ 5,554
Future income tax	1,840	1,798	1,764	1,724
Environmental remediation costs	729	681	613	564
Pension and other post retirement benefits deferrals	219	198	185	157
Revenue taxes	167	163	161	158
Surcharge for New York State assessment	143	90	133	82
Deferred storm costs	125	128	79	80
Net electric deferrals	116	121	116	121
Deferred derivative losses – long-term	78	60	61	44
O&R transition bond charges	43	44	—	—
Preferred stock redemption	30	—	30	—
Workers' compensation	22	23	21	23
Property tax reconciliation	13	13	—	—
Recoverable energy costs – long-term	—	14	—	14
Other	157	152	145	140
Regulatory assets – long-term	9,276	9,337	8,645	8,661
Deferred derivative losses – current	192	164	159	140
Regulatory assets – current	192	164	159	140
Total Regulatory Assets	$ 9,468	$ 9,501	$ 8,804	$ 8,801
Regulatory liabilities				
Allowance for cost of removal less salvage	$ 457	$ 448	$ 379	$ 372
Property tax reconciliation	68	35	68	35
World Trade Center settlement proceeds	62	62	62	62
Net unbilled revenue deferrals	51	104	51	104
Long-term interest rate reconciliation	42	30	42	30
Carrying charges on transmission and distribution net plant	41	38	18	14
Gas line losses	17	21	17	21
Expenditure prudence proceeding	8	11	8	11
Energy efficiency programs	6	22	6	20
Other	94	206	79	192
Regulatory liabilities – long-term	846	977	730	861
Electric surcharge offset	134	—	134	—
Refundable energy costs – current	99	51	55	12
Revenue decoupling mechanism	51	66	51	66
Deferred derivative gains – current	2	1	2	1
Regulatory liabilities – current	286	118	242	79
Total Regulatory Liabilities	$ 1,132	$ 1,095	$ 972	$ 940

Note C — Capitalization

In March 2012, CECONY issued $400 million of 4.20 percent 30-year debentures, $239 million of the net proceeds from the sale of which were used to redeem on May 1, 2012 all outstanding shares of its $5 Cumulative Preferred Stock and Cumulative Preferred Stock ($100 par value).

The carrying amounts and fair values of long-term debt are:

(millions of dollars)	March 31, 2012		December 31, 2011	
Long-Term Debt (including current portion)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Con Edison	$ 11,071	$ 12,892	$ 10,673	$ 12,744
CECONY	$ 10,143	$ 11,757	$ 9,745	$ 11,593

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Fair values of long-term debt have been estimated primarily using available market information. For Con Edison, $12,256 million and $636 million of the fair value of long-term debt at March 31, 2012 are classified as Level 2 and Level 3, respectively. For CECONY, $11,121 million and $636 million of the fair value of long-term debt at March 31, 2012 are classified as Level 2 and Level 3, respectively (see Note K).

Note D — Short-Term Borrowing

At March 31, 2012, Con Edison and CECONY had no commercial paper outstanding. The Companies have not borrowed under their October 2011 credit agreement. Con Edison had $183 million of letters of credit outstanding under the credit agreement (including $168 million for CECONY).

Note E — Pension Benefits

Net Periodic Benefit Cost

The components of the Companies' net periodic benefit costs for the three months ended March 31, 2012 and 2011 were as follows:

	Con Edison		CECONY	
(Millions of Dollars)	**2012**	**2011**	**2012**	**2011**
Service cost – including administrative expenses	$ 59	$ 47	$ 55	$ 44
Interest cost on projected benefit obligation	137	140	128	131
Expected return on plan assets	(176)	(183)	(168)	(175)
Amortization of net actuarial loss	177	132	168	125
Amortization of prior service costs	2	2	2	2
NET PERIODIC BENEFIT COST	$ 199	$ 138	$ 185	$ 127
Cost capitalized	(64)	(48)	(63)	(45)
Cost deferred	(37)	(51)	(38)	(52)
Cost charged to operating expenses	$ 98	$ 39	$ 84	$ 30

Expected Contributions

Based on estimates as of March 31, 2012, the Companies expect to make contributions to the pension plan during 2012 of $775 million (of which $721 million is to be contributed by CECONY). During the first quarter of 2012, CECONY contributed $184 million to the pension plan. The Companies expect to fund $12 million for the non-qualified supplemental plans in 2012. The Companies' policy is to fund their accounting cost to the extent tax deductible.

Note F — Other Postretirement Benefits

Net Periodic Benefit Cost

The components of the Companies' net periodic postretirement benefit costs for the three months ended March 31, 2012 and 2011 were as follows:

	Con Edison		CECONY	
(Millions of Dollars)	**2012**	**2011**	**2012**	**2011**
Service cost	$ 7	$ 6	$ 5	$ 5
Interest cost on accumulated other postretirement benefit obligation	18	21	16	18
Expected return on plan assets	(21)	(22)	(18)	(19)
Amortization of net actuarial loss	25	22	22	20
Amortization of prior service cost	(5)	(2)	(4)	(3)
Amortization of transition obligation	—	1	—	1
NET PERIODIC POSTRETIREMENT BENEFIT COST	$ 24	$ 26	$ 21	$ 22
Cost capitalized	(8)	(9)	(7)	(8)
Cost charged	7	4	4	3
Cost charged to operating expenses	$ 23	$ 21	$ 18	$ 17

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Expected Contributions

Based on estimates as of March 31, 2012, Con Edison expects to make a contribution of $87 million, including $74 million for CECONY, to the other postretirement benefit plans in 2012.

Note G — Environmental Matters

Superfund Sites

Hazardous substances, such as asbestos, polychlorinated biphenyls (PCBs) and coal tar, have been used or generated in the course of operations of the Utilities and their predecessors and are present at sites and in facilities and equipment they currently or previously owned, including sites at which gas was manufactured or stored.

The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 and similar state statutes (Superfund) impose joint and several liability, regardless of fault, upon generators of hazardous substances for investigation and remediation costs (which include costs of demolition, removal, disposal, storage, replacement, containment, and monitoring) and natural resource damages. Liability under these laws can be material and may be imposed for contamination from past acts, even though such past acts may have been lawful at the time they occurred. The sites at which the Utilities have been asserted to have liability under these laws, including their manufactured gas plant sites and any neighboring areas to which contamination may have migrated, are referred to herein as "Superfund Sites."

For Superfund Sites where there are other potentially responsible parties and the Utilities are not managing the site investigation and remediation, the accrued liability represents an estimate of the amount the Utilities will need to pay to investigate and, where determinable, discharge their related obligations. For Superfund Sites (including the manufactured gas plant sites) for which one of the Utilities is managing the investigation and remediation, the accrued liability represents an estimate of the company's share of undiscounted cost to investigate the sites and, for sites that have been investigated in whole or in part, the cost to remediate the sites, if remediation is necessary and if a reasonable estimate of such cost can be made. Remediation costs are estimated in light of the information available, applicable remediation standards, and experience with similar sites.

The accrued liabilities and regulatory assets related to Superfund Sites at March 31, 2012 and December 31, 2011 were as follows:

	Con Edison		CECONY	
(Millions of Dollars)	2012	2011	2012	2011
Accrued Liabilities:				
Manufactured gas plant sites	$ 466	$ 422	$ 351	$ 307
Other Superfund Sites	71	67	70	66
Total	$ 537	$ 489	$ 421	$ 373
Regulatory assets	$ 729	$ 681	$ 613	$ 564

Most of the accrued Superfund Site liability relates to sites that have been investigated, in whole or in part. However, for some of the sites, the extent and associated cost of the required remediation has not yet been determined. As investigations progress and information pertaining to the required remediation becomes available, the Utilities expect that additional liability may be accrued, the amount of which is not presently determinable but may be material. Under their current rate agreements, the Utilities are permitted to recover or defer as regulatory assets (for subsequent recovery through rates) certain site investigation and remediation costs. In February 2011, the NYSPSC initiated a proceeding to examine the existing mechanisms pursuant to which utilities recover such costs and possible alternatives.

Environmental remediation costs incurred and insurance recoveries received related to Superfund Sites for the three months ended March 31, 2012 and 2011, were as follows:

	Con Edison		CECONY	
(Millions of Dollars)	2012	2011	2012	2011
Remediation costs incurred	$ 7	$ 6	$ 7	$ 5
Insurance recoveries received	—	—	—	—

In 2010, CECONY estimated that for its manufactured gas plant sites, its aggregate undiscounted potential liability for the investigation and remediation of coal tar and/or other manufactured gas plant-related environmental contaminants could range up to

$1.9 billion. In 2010, O&R estimated that for its manufactured gas plant sites, each of which has been investigated, the aggregate undiscounted potential liability for the remediation of such contaminants could range up to $200 million. These estimates were based on the assumption that there is contamination at all sites, including those that have not yet been fully investigated and additional assumptions about the extent of the contamination and the type and extent of the remediation that may be required. Actual experience may be materially different.

Asbestos Proceedings

Suits have been brought in New York State and federal courts against the Utilities and many other defendants, wherein a large number of plaintiffs sought large amounts of compensatory and punitive damages for deaths and injuries allegedly caused by exposure to asbestos at various premises of the Utilities. The suits that have been resolved, which are many, have been resolved without any payment by the Utilities, or for amounts that were not, in the aggregate, material to them. The amounts specified in all the remaining thousands of suits total billions of dollars; however, the Utilities believe that these amounts are greatly exaggerated, based on the disposition of previous claims. In 2010, CECONY estimated that its aggregate undiscounted potential liability for these suits and additional suits that may be brought over the next 15 years is $10 million. The estimate was based upon a combination of modeling, historical data analysis and risk factor assessment. Actual experience may be materially different. In addition, certain current and former employees have claimed or are claiming workers' compensation benefits based on alleged disability from exposure to asbestos. Under its current rate agreements, CECONY is permitted to defer as regulatory assets (for subsequent recovery through rates) costs incurred for its asbestos lawsuits and workers' compensation claims. The accrued liability for asbestos suits and workers' compensation proceedings (including those related to asbestos exposure) and the amounts deferred as regulatory assets for the Companies at March 31, 2012 and December 31, 2011 were as follows:

	Con Edison		CECONY	
(Millions of Dollars)	**2012**	**2011**	**2012**	**2011**
Accrued liability – asbestos suits	$ 10	$ 10	$ 10	$ 10
Regulatory assets – asbestos suits	$ 10	$ 10	$ 10	$ 10
Accrued liability – workers' compensation	$ 96	$ 98	$ 92	$ 93
Regulatory assets – workers' compensation	$ 22	$ 23	$ 21	$ 23

Note H — Other Material Contingencies

Manhattan Steam Main Rupture

In July 2007, a CECONY steam main located in midtown Manhattan ruptured. It has been reported that one person died and others were injured as a result of the incident. Several buildings in the area were damaged. Debris from the incident included dirt and mud containing asbestos. The response to the incident required the closing of several buildings and streets for various periods. Approximately 93 suits are pending against the company seeking generally unspecified compensatory and, in some cases, punitive damages, for personal injury, property damage and business interruption. The company has not accrued a liability for the suits. The company has notified its insurers of the incident and believes that the policies in force at the time of the incident will cover most of the company's costs, which the company is unable to estimate, but which could be substantial, to satisfy its liability to others in connection with the incident.

Investigations of Vendor Payments

In January 2009, CECONY commenced an internal investigation relating to the arrests of certain employees and retired employees (all of whom have since been convicted) for accepting kickbacks from contractors that performed construction work for the company. The company has retained a law firm, which has retained an accounting firm, to assist in the company's investigation. The company has provided information to governmental authorities, which consider the company to be a victim of unlawful conduct, in connection with their investigation of the arrested employees and contractors. The company has terminated its employment of the arrested employees and its contracts with the contractors. In February 2009, the NYSPSC commenced a proceeding that, among other things, will examine the prudence of certain of the company's expenditures relating to the arrests and consider whether additional expenditures should also be examined (see "Other Regulatory Matters" in Note B).

CECONY is also investigating the September 2010 arrest of a retired employee (who has since been convicted of participating in a bribery scheme in which the employee received payments from two companies that supplied materials to the company) and the January 2011 arrest of an employee (for accepting kickbacks from an engineering firm that performed work for the company). CECONY has provided information to governmental authorities in connection with their ongoing investigations of these matters.

The company, based upon its evaluation of its internal controls for 2011 and previous years, believes that the controls were effective to provide reasonable assurance that its financial statements have been fairly presented, in all material respects, in conformity with generally accepted accounting principles. Because the company's investigations are ongoing, the company is unable to predict the impact of any of the employees' unlawful conduct on the company's internal controls, business, results of operations or financial position.

Lease In/Lease Out Transactions

In each of 1997 and 1999, Con Edison Development entered into a transaction in which it leased property and then immediately subleased it back to the lessor (termed "Lease In/Lease Out," or LILO transactions). The transactions respectively involve electric generating and gas distribution facilities in the Netherlands, with a total investment of $259 million. The transactions were financed with $93 million of equity and $166 million of non-recourse, long-term debt secured by the underlying assets. In accordance with the accounting rules for leases, Con Edison is accounting for the two LILO transactions as leveraged leases. Accordingly, the company's investment in these leases, net of non-recourse debt, is carried as a single amount in Con Edison's consolidated balance sheet and income is recognized pursuant to a method that incorporates a level rate of return for those years when net investment in the lease is positive, based upon the after-tax cash flows projected at the inception of the leveraged leases. The company's investment in these leveraged leases was $(65) million at March 31, 2012 and $(55) million at December 31, 2011 and is comprised of a $228 million gross investment less $293 million of deferred tax liabilities at March 31, 2012 and $234 million gross investment less $289 million of deferred tax liabilities at December 31, 2011.

On audit of Con Edison's tax return for 1997, the IRS disallowed the tax losses in connection with the 1997 LILO transaction. In December 2005, Con Edison paid a $0.3 million income tax deficiency asserted by the IRS for the tax year 1997 with respect to the 1997 LILO transaction. In April 2006, the company paid interest of $0.2 million associated with the deficiency and commenced an action in the United States Court of Federal Claims, entitled Consolidated Edison Company of New York, Inc. v. United States, to obtain a refund of this tax payment and interest. A trial was completed in November 2007. In October 2009, the court issued a decision in favor of the company concluding that the 1997 LILO transaction was, in substance, a true lease that possessed economic substance, the loans relating to the lease constituted bona fide indebtedness, and the deductions for the 1997 LILO transactions claimed by the company in its 1997 federal income tax return are allowable. The IRS appealed the decision in December 2011.

In connection with its audit of Con Edison's federal income tax returns for 1998 through 2007, the IRS disallowed $416 million of net tax deductions taken with respect to both of the LILO transactions for the tax years. Con Edison is pursuing administrative appeals of these audit level disallowances. In connection with its audit of Con Edison's federal income tax returns for 2010, 2009 and 2008, the IRS has disallowed $40 million, $41 million and $42 million, respectively, of

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net tax deductions taken with respect to both of the LILO transactions. When these audit level disallowances become appealable, Con Edison intends to file an appeal of the disallowances.

Con Edison believes that its LILO transactions have been correctly reported, and has not recorded any reserve with respect to the disallowance of tax losses, or related interest, in connection with its LILO transactions. Con Edison's estimated tax savings, reflected in its financial statements, from the two LILO transactions through March 31, 2012, in the aggregate, was $240 million. If Con Edison were required to repay all or a portion of these amounts, it would also be required to pay interest of up to $114 million net of tax at March 31, 2012.

Pursuant to the accounting rules for leveraged lease transactions, the expected timing of income tax cash flows generated by Con Edison's LILO transactions are required to be reviewed at least annually. If the expected timing of the cash flows is revised, the rate of return and the allocation of income would be recalculated from the inception of the LILO transactions, and the company would be required to recalculate the accounting effect of the LILO transactions, which would result in a charge to earnings that could have a material adverse effect on the company's results of operations.

Guarantees

Con Edison and its subsidiaries enter into various agreements providing financial or performance assurance primarily to third parties on behalf of their subsidiaries. Maximum amounts guaranteed by Con Edison totaled $760 million at March 31, 2012 and December 31, 2011, respectively.

A summary, by type and term, of Con Edison's total guarantees at March 31, 2012 is as follows:

Guarantee Type	0 – 3 years	4 – 10 years	> 10 years	Total
		(Millions of Dollars)		
Energy transactions	$ 637	$ 4	$ 66	$ 707
Intra-company guarantees	15	—	1	16
Other guarantees	33	4	—	37
TOTAL	$ 685	$ 8	$ 67	$ 760

Energy Transactions — Con Edison guarantees payments on behalf of its competitive energy businesses in order to facilitate physical and financial transactions in gas, pipeline capacity, transportation, oil, electricity and energy services. To the extent that liabilities exist under the contracts subject to these guarantees, such liabilities are included in Con Edison's consolidated balance sheet.

Intra-company Guarantees — Con Edison guarantees electricity sales made by Con Edison Energy and Con Edison Solutions to O&R and CECONY.

Other Guarantees — Con Edison and Con Edison Development also guarantee the following:

- $7 million relates to guarantees issued by Con Edison to CECONY covering a former Con Edison subsidiary's lease payment to use CECONY's conduit system in accordance with a tariff approved by the NYSPSC and a guarantee issued by Con Edison to a landlord to guarantee the former subsidiary's obligations under a building lease. The former subsidiary is obligated to reimburse Con Edison for any payments made under these guarantees. This obligation is fully secured by letters of credit;
- $25 million for guarantees provided by Con Edison to Travelers Insurance Company for indemnity agreements for surety bonds in connection with energy service projects performed by Con Edison Solutions;
- $5 million for guarantees provided by Con Edison Development to Travelers Insurance Company for indemnity agreements for surety bonds in connection with the construction and operation of solar facilities performed by its subsidiaries; and
- Con Edison, on behalf of Con Edison Solutions, as a retail electric provider, issued a guarantee to the Public Utility Commission of Texas with no specified limitation on the amount guaranteed, covering the payment of all obligations of a retail electric provider. Con Edison's estimate of the maximum potential obligation is $5 million as of March 31, 2012.

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Note I — Financial Information by Business Segment

The financial data for the business segments are as follows:

	For the Three Months Ended March 31,							
	Operating revenues		Inter-segment revenues		Depreciation and amortization		Operating income	
(Millions of Dollars)	2012	2011	2012	2011	2012	2011	2012	2011
CECONY								
Electric	$ 1,735	$ 1,721	$ 3	$ 3	$ 173	$ 161	$ 224	$ 217
Gas	563	663	1	1	29	27	221	204
Steam	263	325	19	20	16	16	99	125
Consolidation adjustments	—	—	(23)	(24)	—	—	—	—
Total CECONY	$ 2,561	$ 2,709	$ —	$ —	$ 218	$ 204	$ 544	$ 546
O&R								
Electric	$ 128	$ 149	$ —	$ —	$ 9	$ 9	$ 8	$ 10
Gas	82	92	—	—	4	3	30	28
Total O&R	$ 210	$ 241	$ —	$ —	$ 13	$ 12	$ 38	$ 38
Competitive energy businesses	$ 310	$ 408	$ 2	$ 3	$ 2	$ 2	$ (20)	$ 44
Other*	(3)	(9)	(2)	(3)	—	—	(1)	(2)
Total Con Edison	$ 3,078	$ 3,349	$ —	$ —	$ 233	$ 218	$ 561	$ 626

* Parent company expenses, primarily interest, and consolidation adjustments. Other does not represent a business segment.

Note J — Derivative Instruments and Hedging Activities

Under the accounting rules for derivatives and hedging, derivatives are recognized on the balance sheet at fair value, unless an exception is available under the accounting rules. Certain qualifying derivative contracts have been designated as normal purchases or normal sales contracts. These contracts are not reported at fair value under the accounting rules.

Energy Price Hedging

Con Edison's subsidiaries hedge market price fluctuations associated with physical purchases and sales of electricity, natural gas, and steam by using derivative instruments including futures, forwards, basis swaps, options, transmission congestion contracts and financial transmission rights contracts. The fair values of the Companies' commodity derivatives at March 31, 2012 and December 31, 2011 were as follows:

	Con Edison		CECONY	
(Millions of Dollars)	2012	2011	2012	2011
Fair value of net derivative assets/(liabilities) – gross	$ (331)	$ (249)	$ (181)	$ (144)
Impact of netting of cash collateral	156	110	64	46
Fair value of net derivative assets/(liabilities) – net	$ (175)	$ (139)	$ (117)	$ (98)

Credit Exposure

The Companies are exposed to credit risk related to transactions entered into primarily for the various energy supply and hedging activities by the Utilities and the competitive energy businesses. The Companies use credit policies to manage this risk, including an established credit approval process, monitoring of counterparty limits, netting provisions within agreements, collateral or prepayment arrangements, credit insurance and credit default swaps.

At March 31, 2012, Con Edison and CECONY had $121 million and $12 million of credit exposure in connection with energy supply and hedging activities, net of collateral, respectively. Con Edison's net credit exposure consisted of $46 million with investment-grade counterparties, $37 million with commodity exchange brokers, $36 million with independent system operators and $2 million with non-rated counterparties. CECONY's net credit exposure was with commodity exchange brokers.

Economic Hedges

The Companies enter into certain derivative instruments that do not qualify or are not designated as hedges under the accounting rules for derivatives and hedging. However, management believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices.

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The fair values of the Companies' commodity derivatives at March 31, 2012 were:

(Millions of Dollars)	**Fair Value of Commodity Derivatives (a) Balance Sheet Location**	**Con Edison**	**CECONY**
	Derivatives Asset		
Current	Other current assets	$ 179	$ 20
Long-term	Other deferred charges and non-current assets	25	6
Total derivatives asset		$ 204	$ 26
Impact of netting		(134)	—
Net derivatives asset		$ 70	$ 26
	Derivatives Liability		
Current	Fair value of derivative liabilities	$ 433	$ 149
Long-term	Fair value of derivative liabilities	102	58
Total derivatives liability		$ 535	$ 207
Impact of netting		(290)	(64)
Net derivatives liability		$ 245	$ 143

(a) Qualifying derivative contracts, which have been designated as normal purchases or normal sales contracts, are not reported at fair value under the accounting rules for derivatives and hedging and, therefore, are excluded from the table.

The fair values of the Companies' commodity derivatives at December 31, 2011 were:

(Millions of Dollars)	**Fair Value of Commodity Derivatives (a) Balance Sheet Location**	**Con Edison**	**CECONY**
	Derivatives Asset		
Current	Other current assets	$ 139	$ 16
Long-term	Other deferred charges and non-current assets	26	14
Total derivatives asset		$ 165	$ 30
Impact of netting		(95)	(6)
Net derivatives asset		$ 70	$ 24
	Derivatives Liability		
Current	Fair value of derivative liabilities	$ 331	$ 127
Long-term	Fair value of derivative liabilities	83	48
Total derivatives liability		$ 414	$ 175
Impact of netting		(205)	(53)
Net derivatives liability		$ 209	$ 122

(a) Qualifying derivative contracts, which have been designated as normal purchases or normal sales contracts, are not reported at fair value under the accounting rules for derivatives and hedging and, therefore, are excluded from the table.

The Utilities generally recover all of their prudently incurred fuel, purchased power and gas cost, including hedging gains and losses, in accordance with rate provisions approved by the applicable state utility commissions. In accordance with the accounting rules for regulated operations, the Utilities record a regulatory asset or liability to defer recognition of unrealized gains and losses on their electric and gas derivatives. As gains and losses are realized in future periods, they will be recognized as purchased power, gas and fuel costs in the Companies' consolidated income statements. Con Edison's competitive energy businesses record realized and unrealized gains and losses on their derivative contracts in earnings in the reporting period in which they occur.

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The following table presents the changes in the fair values of commodity derivatives that have been deferred or recognized in earnings for the three months ended March 31, 2012:

Realized and Unrealized Gains/(Losses) on Commodity Derivatives (a)
Deferred or Recognized in Income for the Three Months Ended March 31, 2012

(Millions of Dollars)	**Balance Sheet Location**	**Con Edison**	**CECONY**
Pre-tax gains/(losses) deferred in accordance with accounting rules for regulated operations:			
Current	Deferred derivative gains	$ 1	$ 1
Total deferred gains		$ 1	$ 1
Current	Deferred derivative losses	$ (28)	$ (19)
Current	Recoverable energy costs	(74)	(56)
Long-term	Regulatory assets	(18)	(17)
Total deferred losses		$ (120)	$ (92)
Net deferred losses		$ (119)	$ (91)
	Income Statement Location		
Pre-tax loss recognized in income			
	Purchased power expense	$ (86)(b)	$ —
	Gas purchased for resale	(1)	—
	Non-utility revenue	(3)(b)	—
Total pre-tax loss recognized in income		$ (90)	$ —

(a) Qualifying derivative contracts, which have been designated as normal purchases or normal sales contracts, are not reported at fair value under the accounting rules for derivatives and hedging and, therefore, are excluded from the table.

(b) For the three months ended March 31, 2012, Con Edison recorded in non-utility revenues and purchased power expense an unrealized pre-tax loss of $(4) million and $(27) million, respectively.

The following table presents the changes in the fair values of commodity derivatives that have been deferred or recognized in earnings for the three months ended March 31, 2011:

Realized and Unrealized Gains/(Losses) on Commodity Derivatives (a)
Deferred or Recognized in Income for the Three Months Ended March 31, 2011

(Millions of Dollars)	**Balance Sheet Location**	**Con Edison**	**CECONY**
Pre-tax gains/(losses) deferred in accordance with accounting rules for regulated operations:			
Current	Deferred derivative gains	$ 6	$ 5
Long-term	Regulatory liabilities	3	3
Total deferred gains		$ 9	$ 8
Current	Deferred derivative losses	$ 44	$ 35
Current	Recoverable energy costs	(49)	(42)
Long-term	Regulatory assets	17	11
Total deferred losses		$ 12	$ 4
Net deferred losses		$ 21	$ 12
	Income Statement Location		
Pre-tax gain/(loss) recognized in income			
	Purchased power expense	$ (21)(b)	$ —
	Gas purchased for resale	(6)	—
	Non-utility revenue	10(b)	—
Total pre-tax gain/(loss) recognized in income		$ (17)	$ —

(a) Qualifying derivative contracts, which have been designated as normal purchases or normal sales contracts, are not reported at fair value under the accounting rules for derivatives and hedging and, therefore, are excluded from the table.

(b) For the three months ended March 31, 2011, Con Edison recorded in non-utility revenues and purchased power expense an unrealized pre-tax gain/(loss) of $(13) million and $50 million, respectively.

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As of March 31, 2012, Con Edison had 1,392 contracts, including 582 CECONY contracts, which were considered to be derivatives under the accounting rules for derivatives and hedging (excluding qualifying derivative contracts, which have been designated as normal purchases or normal sales contracts). The following table presents the number of contracts by commodity type:

	Electric Derivatives				Gas Derivatives		
	Number of Energy Contracts (a)	MWhs (b)	Number of Capacity Contracts (a)	MWs (b)	Number of Contracts (a)	Dths (b)	Total Number of Contracts (a)
Con Edison	754	16,197,114	59	7,639	579	91,840,940	1,392
CECONY	141	3,771,625	—	—	441	84,940,000	582

(a) Qualifying derivative contracts, which have been designated as normal purchases or normal sales contracts, are not reported at fair value under the accounting rules for derivatives and hedging and, therefore, are excluded from the table.

(b) Volumes are reported net of long and short positions.

The Companies also enter into electric congestion and gas basis swap contracts to hedge the congestion and transportation charges which are associated with electric and gas contracts and hedged volumes.

The collateral requirements associated with, and settlement of, derivative transactions are included in net cash flows from operating activities in the Companies' consolidated statement of cash flows. Most derivative instrument contracts contain provisions that may require the Companies to provide collateral on derivative instruments in net liability positions. The amount of collateral to be provided will depend on the fair value of the derivative instruments and the Companies' credit ratings.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a net liability position and collateral posted at March 31, 2012, and the additional collateral that would have been required to be posted had the lowest applicable credit rating been reduced one level and to below investment grade were:

(Millions of Dollars)	Con Edison (a)	CECONY (a)
Aggregate fair value – net liabilities	$ 245	$ 143
Collateral posted	$ 64	$ 51
Additional collateral (b) (downgrade one level from current ratings (c))	$ 35	$ 18
Additional collateral (b) (downgrade to below investment grade from current ratings (c))	$ 225(d)	$ 106(d)

(a) Non-derivative transactions for the purchase and sale of electricity and gas and qualifying derivative instruments, which have been designated as normal purchases or normal sales, are excluded from the table. These transactions primarily include purchases of electricity from independent system operators. In the event the Utilities and Con Edison's competitive energy businesses were no longer extended unsecured credit for such purchases, the Companies would be required to post collateral, which at March 31, 2012, would have amounted to an estimated $39 million for Con Edison, including $9 million for CECONY. For certain other such non-derivative transactions, the Companies could be required to post collateral under certain circumstances, including in the event counterparties had reasonable grounds for insecurity.

(b) The Companies measure the collateral requirements by taking into consideration the fair value amounts of derivative instruments that contain credit-risk-related contingent features that are in a net liabilities position plus amounts owed to counterparties for settled transactions and amounts required by counterparties for minimum financial security. The fair value amounts represent unrealized losses, net of any unrealized gains where the Companies have a legally enforceable right of setoff.

(c) The current ratings are Moody's, S&P and Fitch long-term credit rating of, as applicable, Con Edison (Baa1/BBB+/BBB+), CECONY (A3/A-/A-) or O&R (Baa1/A-/A-). Credit ratings assigned by rating agencies are expressions of opinions that are subject to revision or withdrawal at any time by the assigning rating agency.

(d) Derivative instruments that are net assets have been excluded from the table. At March 31, 2012, if Con Edison had been downgraded to below investment grade, it would have been required to post additional collateral for such derivative instruments of not more than $23 million.

Interest Rate Swaps

O&R has an interest rate swap pursuant to which it pays a fixed-rate of 6.09 percent and receives a LIBOR-based variable rate. The fair value of this interest rate swap at March 31, 2012 was an unrealized loss of $8 million, which has been included in Con Edison's consolidated balance sheet as a noncurrent liability/fair value of derivative liabilities and a regulatory asset. The increase in the fair value of the swap for the three months ended March 31, 2012 was immaterial. In the event O&R's credit rating was downgraded to BBB- or lower by S&P or Baa3 or lower by Moody's, the swap counterparty could elect to terminate the agreement and, if it did so, the parties would then be required to settle the transaction.

Note K — Fair Value Measurements

The accounting rules for fair value measurements and disclosures define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date in a principal or most advantageous market. Fair value is a market-based measurement that is determined based on inputs, which refer broadly to assumptions that market participants use in pricing assets or liabilities. These inputs can be readily observable, market corroborated, or generally unobservable firm inputs. The Companies often make certain assumptions that market participants would use in pricing the asset or liability, including assumptions about risk, and the risks inherent in the inputs to valuation techniques. The Companies use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The accounting rules for fair value measurements and disclosures established a fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value in three broad levels. The rules require that assets and liabilities be classified in their entirety based on the level of input that is significant to the fair value measurement. Assessing the significance of a particular input may require judgment considering factors specific to the asset or liability, and may affect the valuation of the asset or liability and their placement within the fair value hierarchy. The Companies classify fair value balances based on the fair value hierarchy defined by the accounting rules for fair value measurements and disclosures as follows:

- Level 1 – Consists of assets or liabilities whose value is based on unadjusted quoted prices in active markets at the measurement date. An active market is one in which transactions for assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes contracts traded on active exchange markets valued using unadjusted prices quoted directly from the exchange.
- Level 2 – Consists of assets or liabilities valued using industry standard models and based on prices, other than quoted prices within Level 1, that are either directly or indirectly observable as of the measurement date. The industry standard models consider observable assumptions including time value, volatility factors, and current market and contractual prices for the underlying commodities, in addition to other economic measures. This category includes contracts traded on active exchanges or in over-the-counter markets priced with industry standard models.
- Level 3 – Consists of assets or liabilities whose fair value is estimated based on internally developed models or methodologies using inputs that are generally less readily observable and supported by little, if any, market activity at the measurement date. Unobservable inputs are developed based on the best available information and subject to cost benefit constraints. This category includes contracts priced using models that are internally developed and contracts placed in illiquid markets. It also includes contracts that expire after the period of time for which quoted prices are available and internal models are used to determine a significant portion of the value.

Effective January 1, 2012, the Companies adopted Accounting Standards Update (ASU) No. 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs". The amendments expand existing disclosure requirements for fair value measurements and make other amendments. For fair value measurements in Level 3, this update requires the Companies to provide a description of the valuation process in place, a quantitative disclosure of unobservable inputs and assumptions used in the measurement as well as a narrative description of the sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs. The update also requires the Companies to disclose any transfers between Levels 1 and 2 of fair value hierarchy measurements and the reasons for the transfers.

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Assets and liabilities measured at fair value on a recurring basis as of March 31, 2012 are summarized below.

	Level 1		Level 2		Level 3		Netting Adjustments (4)		Total	
(Millions of Dollars)	Con Edison	CECONY	Con Edison	CECONY	Con Edison	CECONY	Con Edison	CECONY	Con Edison	CECONY
Derivative assets:										
Commodity (1)	$ 2	$ —	$ 86	$ 4	$ 103	$ 13	$ (122)	$ 9	$ 69	$ 26
Other assets (3)	83	83	—	—	105	95	—	—	188	178
Transfer in (5) (6)	—	—	105	95	—	—	—	—	105	95
Transfer out (5) (6)	—	—	—	—	(105)	(95)	—	—	(105)	(95)
Other assets (3)	$ 83	$ 83	$ 105	$ 95	$ —	$ —	$ —	$ —	$ 188	$ 178
Total	$ 85	$ 83	$ 191	$ 99	$ 103	$ 13	$ (122)	$ 9	$ 257	$ 204
Derivative liabilities:										
Commodity (1)	$ 10	$ 2	$ 316	$ 170	$ 196	$ 26	$ (278)	$ (55)	$ 244	$ 143
Interest rate contract (2)	—	—	—	—	8	—	—	—	8	—
Transfer in (5) (6)	—	—	8	—	—	—	—	—	8	—
Transfer out (5) (6)	—	—	—	—	(8)	—	—	—	(8)	—
Interest rate contract (2)	$ —	$ —	$ 8	$ —	$ —	$ —	$ —	$ —	$ 8	$ —
Total	$ 10	$ 2	$ 324	$ 170	$ 196	$ 26	$ (278)	$ (55)	$ 252	$ 143

(1) A portion of the commodity derivatives categorized in Level 3 is valued using an internally developed model with observable inputs. The models also include some less readily observable inputs resulting in the classification of the entire contract as Level 3. See Note J.

(2) See Note J.

(3) Other assets are comprised of assets such as life insurance contracts within the deferred compensation plan and non-qualified retirement plans.

(4) Amounts represent the impact of legally-enforceable master netting agreements that allow the Companies to net gain and loss positions and cash collateral held or placed with the same counterparties.

(5) The Companies' policy is to recognize transfers into and transfers out of the levels at the end of the reporting period.

(6) Transferred from Level 3 to Level 2 because of reassessment of the levels in the fair value hierarchy within which certain inputs fall.

Assets and liabilities measured at fair value on a recurring basis as of December 31, 2011 are summarized below.

	Level 1		Level 2		Level 3		Netting Adjustments (4)		Total	
(Millions of Dollars)	Con Edison	CECONY	Con Edison	CECONY	Con Edison	CECONY	Con Edison	CECONY	Con Edison	CECONY
Derivative assets:										
Commodity (1)	$ 3	$ —	$ 64	$ 8	$ 87	$ 11	$ (84)	$ 5	$ 70	$ 24
Other assets (3)	76	76	—	—	99	90	—	—	175	166
Total	$ 79	$ 76	$ 64	$ 8	$ 186	$ 101	$ (84)	$ 5	$ 245	$ 190
Derivative liabilities:										
Commodity	$ 12	$ 4	$ 222	$ 122	$ 169	$ 37	$ (194)	$ (41)	$ 209	$ 122
Transfer in (5) (6) (7)	—	—	26	25	6	6	—	—	32	31
Transfer out (5) (6) (7)	—	—	(6)	(6)	(26)	(25)	—	—	(32)	(31)
Commodity (1)	$ 12	$ 4	$ 242	$ 141	$ 149	$ 18	$ (194)	$ (41)	$ 209	$ 122
Interest rate contract (2)	—	—	—	—	8	—	—	—	8	—
Total	$ 12	$ 4	$ 242	$ 141	$ 157	$ 18	$ (194)	$ (41)	$ 217	$ 122

(1) A portion of the commodity derivatives categorized in Level 3 is valued using an internally developed model with observable inputs. The models also include some less readily observable inputs resulting in the classification of the entire contract as Level 3. See Note J.

(2) See Note J.

(3) Other assets are comprised of assets such as life insurance contracts within the deferred compensation plan and non-qualified retirement plans.

(4) Amounts represent the impact of legally-enforceable master netting agreements that allow the Companies to net gain and loss positions and cash collateral held or placed with the same counterparties.

(5) The Companies' policy is to recognize transfers into and transfers out of the levels at the end of the reporting period.

(6) Transferred from Level 2 to Level 3 because of reassessment of the levels in the fair value hierarchy within which certain inputs fall.

(7) Transferred from Level 3 to Level 2 because of availability of observable market data due to decrease in the terms of certain contracts from beyond one year as of December 31, 2010 to less than one year as of December 31, 2011.

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The employees in the risk management groups of the Utilities and the competitive energy businesses develop and maintain the Companies' valuation policies and procedures for, and verify pricing and fair value valuation of, commodity derivatives. Under the Companies' policies and procedures, multiple independent sources of information are obtained for forward price curves used to value commodity derivatives. Fair value and changes in fair value of commodity derivatives are reported on a monthly basis to the Companies' risk committees, comprised of officers and employees of the Companies that oversee energy hedging at the Utilities and the competitive energy businesses. The managers of the risk management groups report to the Companies' Vice President and Treasurer.

(Millions of Dollars)	Fair Value of Level 3 at 3/31/2012	Valuation Techniques	Unobservable Inputs
Con Edison			
Commodity	$ (93)	Market approach (1)	Discount for inactive markets and/or illiquid locations (2)
CECONY			
Commodity	$ (13)	Market approach (1)	Discount for inactive markets and/or illiquid locations (2)

(1) The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets and liabilities. The commodity derivatives are valued using quoted prices or internally developed models with observable inputs, adjusted for certain contracts that are traded in inactive markets and/or at illiquid locations. The unobservable inputs used in the Companies' models do not have a significant impact on the valuation.

(2) Significant increases or decreases in any of these inputs in isolation would have a limited impact on fair value measurement. Generally, a change in the fair value measurement is linearly based on changes in these inputs.

The table listed below provides a reconciliation of the beginning and ending net balances for assets and liabilities measured at fair value as of March 31, 2012 and 2011 and classified as Level 3 in the fair value hierarchy:

	For the Three Months Ended March 31, 2012								
		Total Gains/(Losses)— Realized and Unrealized							
(Millions of Dollars)	Beginning Balance as of January 1, 2012	Included in Earnings	Included in Regulatory Assets and Liabilities	Purchases	Issuances	Sales	Settlements	Transfer In/Out of Level 3	Ending Balance as of March 31, 2012
Con Edison									
Derivatives:									
Commodity	$ (62)	$ (58)	$ (17)	$ 6	$ —	$ —	$ 38	$ —	$ (93)
Interest rate contract	(8)	(1)	—	—	—	—	1	8	—
Other assets (1)	99	3	3	—	—	—	—	(105)	—
Total	$ 29	$ (56)	$ (14)	$ 6	$ —	$ —	$ 39	$ (97)	$ (93)
CECONY									
Derivatives:									
Commodity	$ (7)	$ (5)	$ (7)	$ 6	$ —	$ —	$ —	$ —	$ (13)
Other assets (1)	90	3	2	—	—	—	—	(95)	—
Total	$ 83	$ (2)	$ (5)	$ 6	$ —	$ —	$ —	$ (95)	$ (13)

(1) Amounts included in earnings are reported in investment and other income on the consolidated income statement.

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	For the Three Months Ended March 31, 2011								
		Total Gains/(Losses)— Realized and Unrealized							
(Millions of Dollars)	Beginning Balance as of January 1, 2011	Included in Earnings	Included in Regulatory Assets and Liabilities	Purchases	Issuances	Sales	Settlements	Transfer In/Out of Level 3	Ending Balance as of March 31, 2011
Con Edison									
Derivatives:									
Commodity	$ (88)	$ 9	$ 40	$ 10	$ —	$ —	$ 3	$ (5)	$ (31)
Interest rate contract	(10)	(1)	—	—	—	—	1	—	(10)
Other assets (1)	101	2	2	—	—	—	—	—	105
Total	$ 3	$ 10	$ 42	$ 10	$ —	$ —	$ 4	$ (5)	$ 64
CECONY									
Derivatives:									
Commodity	$ (26)	$ (1)	$ 27	$ 10	$ —	$ —	$ (3)	$ (5)	$ 2
Other assets (1)	92	2	1	—	—	—	—	—	95
Total	$ 66	$ 1	$ 28	$ 10	$ —	$ —	$ (3)	$ (5)	$ 97

(1) Amounts included in earnings are reported in investment and other income on the consolidated income statement.

For the Utilities, realized gains and losses on Level 3 commodity derivative assets and liabilities are reported as part of purchased power, gas and fuel costs. The Utilities generally recover these costs in accordance with rate provisions approved by the applicable state public utilities commissions. See Note A to the financial statements in Item 8 of the Form 10-K. Unrealized gains and losses for commodity derivatives are generally deferred on the consolidated balance sheet in accordance with the accounting rules for regulated operations.

For the competitive energy businesses, realized and unrealized gains and losses on Level 3 commodity derivative assets and liabilities are reported in non-utility revenues ($3 million loss and $12 million loss) and purchased power costs ($43 million loss and $27 million gain) on the consolidated income statement for the three months ended March 31, 2012 and 2011, respectively. The change in fair value relating to Level 3 commodity derivative assets held at March 31, 2012 and 2011 is included in non-utility revenues ($3 million loss and $12 million loss), and purchased power costs ($7 million loss and $29 million gain) on the consolidated income statement for the three months ended March 31, 2012 and 2011, respectively.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At March 31, 2012, the Companies determined that nonperformance risk would have no material impact on their financial position or results of operations. To assess nonperformance risk, the Companies considered information such as collateral requirements, master netting arrangements, letters of credit and parent company guarantees, and applied a market-based method by using the counterparty (for an asset) or the Companies' (for a liability) credit default swaps rates.

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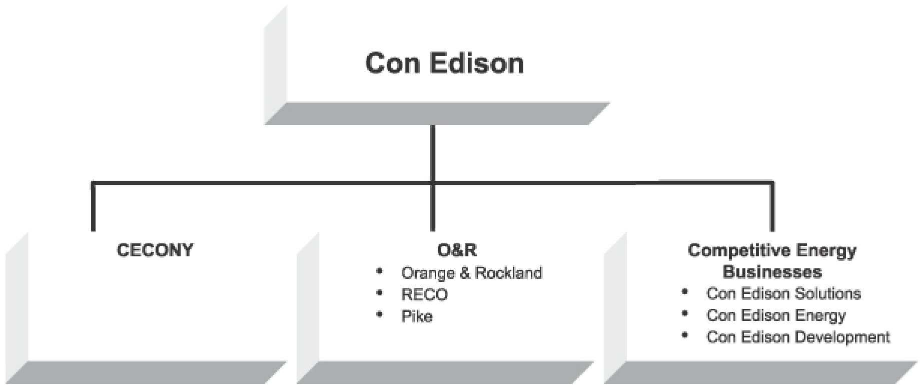
Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations

This combined management's discussion and analysis of financial condition and results of operations (MD&A) relates to the consolidated financial statements (the First Quarter Financial Statements) included in this report of two separate registrants: Consolidated Edison, Inc. (Con Edison) and Consolidated Edison Company of New York, Inc. (CECONY). This MD&A should be read in conjunction with the financial statements and the notes thereto. As used in this report, the term the "Companies" refers to Con Edison and CECONY. CECONY is a subsidiary of Con Edison and, as such, information in this management's discussion and analysis about CECONY applies to Con Edison.

This MD&A should be read in conjunction with the First Quarter Financial Statements and the notes thereto and the MD&A in Item 7 of the Companies' combined Annual Report on Form 10-K for the year ended December 31, 2011 (File Nos. 1-14514 and 1-1217, the Form 10-K).

Information in any item of this report referred to in this discussion and analysis is incorporated by reference herein. The use of terms such as "see" or "refer to" shall be deemed to incorporate by reference into this discussion and analysis the information to which reference is made.

Con Edison, incorporated in New York State in 1997, is a holding company which owns all of the outstanding common stock of CECONY, Orange and Rockland Utilities, Inc. (O&R) and the competitive energy businesses. As used in this report, the term the "Utilities" refers to CECONY and O&R.



CECONY's principal business operations are its regulated electric, gas and steam delivery businesses. O&R's principal business operations are its regulated electric and gas delivery businesses. The competitive energy businesses sell electricity to retail and wholesale customers, provide certain energy-related services, and participate in energy infrastructure projects. Con Edison is evaluating additional opportunities to invest in electric and gas-related businesses.

Con Edison's strategy is to provide reliable energy services, maintain public and employee safety, promote energy efficiency, and develop cost-effective ways of performing its business. Con Edison seeks to be a responsible steward of the environment and enhance its relationships with customers, regulators and members of the communities it serves.

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CECONY

Electric

CECONY provides electric service to approximately 3.3 million customers in all of New York City (except part of Queens) and most of Westchester County, an approximately 660 square mile service area with a population of more than nine million.

Gas

CECONY delivers gas to approximately 1.1 million customers in Manhattan, the Bronx and parts of Queens and Westchester County.

Steam

CECONY operates the largest steam distribution system in the United States by producing and delivering more than 22,000 MMlbs of steam annually to approximately 1,735 customers in parts of Manhattan.

O&R

Electric

O&R and its utility subsidiaries, Rockland Electric Company (RECO) and Pike County Light & Power Company (Pike) (together referred to herein as O&R) provide electric service to approximately 0.3 million customers in southeastern New York and in adjacent areas of northern New Jersey and northeastern Pennsylvania, an approximately 1,350 square mile service area.

Gas

O&R delivers gas to over 0.1 million customers in southeastern New York and adjacent areas of northeastern Pennsylvania.

Competitive Energy Businesses

Con Edison pursues competitive energy opportunities through three wholly-owned subsidiaries: Con Edison Solutions, Con Edison Energy and Con Edison Development. These businesses include the sales and related hedging of electricity to retail and wholesale customers, sales of certain energy-related products and services, and participation in energy infrastructure projects. At March 31, 2012, Con Edison's equity investment in its competitive energy businesses was $343 million and their assets amounted to $837 million.

Certain financial data of Con Edison's businesses is presented below:

	Three months ended March 31, 2012				At March 31, 2012	
(millions of dollars, except percentages)	Operating Revenues		Net Income for Common Stock		Assets	
CECONY	$ 2,561	83%	$ 273	99%	$ 35,755	90%
O&R	210	7%	20	7%	2,455	6%
Total Utilities	2,771	90%	293	106%	38,210	96%
Con Edison Solutions (a)	277	9%	(13)	(5)%	328	1%
Con Edison Energy (a)	30	1%	—	—%	109	—%
Con Edison Development	5	—%	1	—%	520	1%
Other (b)	(5)	—%	(4)	(1)%	534	2%
Total Con Edison	**$ 3,078**	**100%**	**$ 277**	**100%**	**$ 39,701**	**100%**

(a) Net income from the competitive energy businesses for the three months ended March 31, 2012 includes $18 million of net after-tax mark-to-market losses (Con Edison Solutions, $17 million and Con Edison Energy, $1 million).

(b) Represents inter-company and parent company accounting. See "Results of Operations," below.

Con Edison's net income for common stock for the three months ended March 31, 2012 was $277 million or $0.95 a share ($0.94 on a diluted basis) compared with $311 million or $1.07 a share ($1.06 on a diluted basis) for the three months ended March 31, 2011. See "Results of Operations – Summary," below. For segment financial information, see Note I to the First Quarter Financial Statements and "Results of Operations," below.

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Results of Operations — Summary

Net income for common stock for the three months ended March 31, 2012 and 2011 was as follows:

(millions of dollars)	2012	2011
CECONY	$ 273	$ 268
O&R	20	19
Competitive energy businesses (a)	(12)	27
Other (b)	(4)	(3)
Con Edison	**$ 277**	**$ 311**

(a) Includes $(18) million and $22 million of net after-tax mark-to-market (losses)/gains in the three months ended 2012 and 2011, respectively.

(b) Consists of inter-company and parent company accounting.

The Companies' results of operations for the three months ended March 31, 2012, as compared with 2011, reflect changes in the Utilities' rate plans and the effects of the milder winter weather on steam revenues. These rate plans provide for additional revenues to cover expected increases in certain operations and maintenance expenses, and depreciation and property taxes. The results of operations include the operating results of the competitive energy businesses, including net mark-to-market effects.

Operations and maintenance expenses were higher due to pensions, other postretirement benefits and healthcare costs, offset in part by lower operating costs attributable to the milder winter in the 2012 period. Depreciation was higher in the 2012 period reflecting primarily the impact from higher utility plant balances.

The following table presents the estimated effect on earnings per share and net income for common stock for the three months ended 2012 as compared with the 2011 period, resulting from these and other major factors:

	Earnings per Share	Net Income for Common Stock (millions of dollars)
CECONY		
Rate plans, primarily to recover increases in certain costs	$ 0.12	$ 37
Operations and maintenance expenses	(0.10)	(29)
Depreciation	(0.03)	(8)
Other	0.02	5
Total CECONY	0.01	5
O&R	—	1
Competitive energy businesses (a)	(0.13)	(39)
Other, including parent company expenses	—	(1)
Total variations	$ (0.12)	$ (34)

(a) These variations reflect after-tax net mark-to-market losses of $18 million or $0.06 a share in the first quarter of 2012 and after-tax net mark-to-market gains of $22 million or $0.08 a share in the first quarter of 2011.

See "Results of Operations" below for further discussion and analysis of results of operations.

Liquidity and Capital Resources

The Companies' liquidity reflects cash flows from operating, investing and financing activities, as shown on their respective consolidated statement of cash flows and as discussed below. Changes in the Companies' cash and temporary cash investments resulting from operating, investing and financing activities for the three months ended March 31, 2012 and 2011 are summarized as follows:

Con Edison

(millions of dollars)	2012	2011	Variance
Operating activities	$ 402	$ 362	$ 40
Investing activities	(490)	(496)	6
Financing activities	209	312	(103)
Net change	121	178	(57)
Balance at beginning of period	648	338	310
Balance at end of period	$ 769	$ 516	$ 253

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CECONY

(millions of dollars)	2012	2011	Variance
Operating activities	$ 368	$ 72	$ 296
Investing activities	(487)	(413)	(74)
Financing activities	222	291	(69)
Net change	103	(50)	153
Balance at beginning of period	372	78	294
Balance at end of period	$ 475	$ 28	$ 447

Cash Flows from Operating Activities

The Utilities' cash flows from operating activities reflect principally their energy sales and deliveries and cost of operations. The volume of energy sales and deliveries is dependent primarily on factors external to the Utilities, such as growth of customer demand, weather, market prices for energy, economic conditions and measures that promote energy efficiency. Under the revenue decoupling mechanisms in CECONY's electric and gas rate plans and O&R's New York electric and gas rate plans, changes in delivery volumes from levels assumed when rates were approved may affect the timing of cash flows but not net income. The prices at which the Utilities provide energy to their customers are determined in accordance with their rate agreements. In general, changes in the Utilities' cost of purchased power, fuel and gas may affect the timing of cash flows but not net income because the costs are recovered in accordance with rate agreements.

Net income is the result of cash and non-cash (or accrual) transactions. Only cash transactions affect the Companies' cash flows from operating activities. Principal non-cash charges include depreciation, deferred income tax expense and net derivative losses. Principal non-cash credits include amortizations of certain net regulatory liabilities. Non-cash charges or credits may also be accrued under the revenue decoupling and cost reconciliation mechanisms in the Utilities' electric and gas rate plans in New York.

Net cash flows from operating activities for the three months ended March 31, 2012 for Con Edison and CECONY were $40 million and $296 million higher, respectively, than in the 2011 period. The increases in net cash flows reflect primarily the timing of CECONY pension contributions ($184 million in the 2012 period as compared with $491 million in the 2011 period). See Note E to the First Quarter Financial Statements. The increases were offset in part by higher cash collateral paid to brokers and counterparties in the 2012 period ($85 million for Con Edison and $37 million for CECONY).

The change in net cash flows also reflects the timing of payments for and recovery of energy costs. This timing is reflected within changes to accounts receivable – customers, recoverable energy costs and accounts payable balances.

The changes in regulatory assets principally reflect changes in deferred pension costs in accordance with the accounting rules for retirement benefits. See Note B to the First Quarter Financial Statements.

Cash Flows Used in Investing Activities

Net cash flows used in investing activities for Con Edison and CECONY were $6 million lower and $74 million higher, respectively, for the three months ended March 31, 2012 compared with the 2011 period. The changes for Con Edison and CECONY reflect increased utility construction expenditures in 2012. In addition, for Con Edison, the change reflects the return of investment resulting from the receipt of government grant proceeds at the Pilesgrove solar project and lower non-utility construction expenditures.

Cash Flows from Financing Activities

Net cash flows from financing activities for Con Edison and CECONY were $103 million and $69 million lower, respectively, in the three months ended March 31, 2012 compared with the 2011 period.

In March 2012, CECONY issued $400 million of 4.20 percent 30-year debentures, $239 million of the net proceeds from the sale of which were used to redeem on May 1, 2012 all outstanding shares of its $5

Cumulative Preferred Stock and Cumulative Preferred Stock ($100 par value). The Companies had no issuances of long-term debt in 2011.

Cash flows from financing activities of the Companies also reflect commercial paper issuance. The commercial paper amounts outstanding at March 31, 2012 and 2011 and the average daily balances for the three months ended March 31, 2012 and 2011 for Con Edison and CECONY were as follows:

	2012		2011	
(millions of dollars, except Weighted Average Yield)	**Outstanding at March 31**	**Daily average**	**Outstanding at March 31**	**Daily average**
Con Edison	$ —	$ 14	$ 464	$ 140
CECONY	$ —	$ 14	$ 464	$ 140
Weighted average yield	—%	0.3%	0.3%	0.3%

Other Changes in Assets and Liabilities

The following table shows changes in certain assets and liabilities at March 31, 2012, compared with December 31, 2011.

(millions of dollars)	**Con Edison 2012 vs. 2011 Variance**	**CECONY 2012 vs. 2011 Variance**
Assets		
Prepayments	$ 286	$ 287
Regulatory asset – Unrecognized pension and other postretirement costs	(258)	(217)
Liabilities		
Pension and retiree benefits	$ (230)	$ (195)

Prepayments

The increase in prepayments for Con Edison and CECONY reflects primarily CECONY's January 2012 payment of its New York City semi-annual property taxes, offset by three months of amortization, while the December 2011 balance reflects the amortization of the previous semi-annual prepayment. See "Cash Flows from Operating Activities," above.

Regulatory Asset for Unrecognized Pension and Other Postretirement Costs and Noncurrent Liability for Pension and Retiree Benefits

The decrease in the regulatory asset for unrecognized pension and other postretirement costs and the noncurrent liability for pension and retiree benefits reflects the final actuarial valuation of the pension and other retiree benefit plans as measured at December 31, 2011 in accordance with the accounting rules for retirement benefits. The change in the regulatory asset also reflects the year's amortization of accounting costs. The decrease in the noncurrent liability for pension and retiree benefits reflects in part contributions to the plans made by the Utilities in 2012. See Notes B, E and F to the First Quarter Financial Statements.

Capital Requirements and Resources

As of March 31, 2012, there was no material change in the Companies' capital requirements, contractual obligations and capital resources compared to those disclosed under "Capital Requirements and Resources" in Item 1 of the Form 10-K other than as described in Note C to the First Quarter Financial Statements.

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For each of the Companies, the ratio of earnings to fixed charges (Securities and Exchange Commission basis) for the three months ended March 31, 2012 and 2011 and the twelve months ended December 31, 2011 was:

	Ratio of Earnings to Fixed Charges		
	For the Three Months Ended March 31, 2012	For the Three Months Ended March 31, 2011	For the Twelve Months Ended December 31, 2011
Con Edison	3.5	3.9	3.6
CECONY	3.9	3.9	3.8

For each of the Companies, the common equity ratio at March 31, 2012 and December 31, 2011 was:

	Common Equity Ratio (Percent of total capitalization)	
	March 31, 2012	December 31, 2011
Con Edison	53.5	52.5
CECONY	53.1	52.0

Regulatory Matters

CECONY's current electric rate plan covers the three-year period ending March 31, 2013. Either the company or the New York State Public Service Commission (NYSPSC) can initiate a proceeding for a new rate plan. A new rate plan filed by the company would take effect automatically in approximately 11 months unless prior to such time the NYSPSC adopts a rate plan. CECONY understands that the base rates determined pursuant to the current rate plan and the other provisions of the current rate plan would continue in effect after March 31, 2013 until a new rate plan is effective. CECONY is evaluating when it will request a new rate plan in light of, among other things, the return on common equity that the company estimates it could earn after March 31, 2013 under the current rate plan as compared to under a new rate plan. In either case, CECONY expects that the earned return on common equity of its electric business for the rate year ending March 31, 2014 would be less than for the rate year ending March 31, 2013.

For information about a March 2012 NYSPSC order relating to a surcharge that CECONY was to have collected from customers and O&R's February 2012 Joint Proposal with respect to its rates for electric service rendered in New York, see Note B to the First Quarter Financial Statements.

Financial and Commodity Market Risks

The Companies are subject to various risks and uncertainties associated with financial and commodity markets. The most significant market risks include interest rate risk, commodity price risk, credit risk and investment risk.

Interest Rate Risk

The interest rate risk relates primarily to variable rate debt and to new debt financing needed to fund capital requirements, including the construction expenditures of the Utilities and maturing debt securities. Con Edison and its businesses manage interest rate risk through the issuance of mostly fixed-rate debt with varying maturities and through opportunistic refinancing of debt. Con Edison and CECONY estimate that at March 31, 2012, a 10 percent variation in interest rates applicable to its variable rate debt would not result in a material change in annual interest expense. Under CECONY's current gas, steam and electric rate plans, variations in actual long-term debt interest rates are reconciled to levels reflected in rates. Under O&R's current New York rate plans, variations in actual interest expense are reconciled to the level set in rates.

In addition, from time to time, Con Edison and its businesses enter into derivative financial instruments to hedge interest rate risk on certain debt securities. See "Interest Rate Swaps" in Note J to the First Quarter Financial Statements.

Commodity Price Risk

Con Edison's commodity price risk relates primarily to the purchase and sale of electricity, gas and related derivative instruments. The Utilities and Con Edison's competitive energy businesses apply risk management strategies to mitigate their related exposures. See Note J to the First Quarter Financial Statements.

Con Edison estimates that, as of March 31, 2012, a 10 percent decline in market prices would result in a decline in fair value of $47 million for the derivative instruments used by the Utilities to hedge purchases of electricity and gas, of which $39 million is for CECONY and $8 million is for O&R. Con Edison expects that any such change in fair value would be largely offset by directionally opposite changes in the cost of the electricity and gas purchased. In accordance with provisions approved by state regulators, the Utilities generally recover from customers the costs they incur for energy purchased for their customers, including gains and losses on certain derivative instruments used to hedge energy purchased and related costs.

Con Edison's competitive energy businesses use a value-at-risk (VaR) model to assess the market risk of their electricity and gas commodity fixed-price purchase and sales commitments, physical forward contracts and commodity derivative instruments. VaR represents the potential change in fair value of instruments or the portfolio due to changes in market factors, for a specified time period and confidence level. These businesses estimate VaR across their electricity and natural gas commodity businesses using a delta-normal variance/covariance model with a 95 percent confidence level. Since the VaR calculation involves complex methodologies and estimates and assumptions that are based on past experience, it is not necessarily indicative of future results. VaR for transactions associated with hedges on generating assets and commodity contracts, assuming a one-day holding period, for the three months ended March 31, 2012 and the year ended December 31, 2011, respectively, was as follows:

95% Confidence Level, One-Day Holding Period	March 31, 2012	December 31, 2011
	(millions of dollars)	
Average for the period	$ 1	$ 1
High	1	1
Low	1	—

Credit Risk

The Companies are exposed to credit risk related to transactions entered into primarily for the various energy supply and hedging activities by the Utilities and the competitive energy businesses. Credit risk relates to the loss that may result from a counterparty's nonperformance. The Companies use credit policies to manage this risk, including an established credit approval process, monitoring of counterparty limits, netting provisions within agreements and collateral or prepayment arrangements, credit insurance and credit default swaps. The Companies measure credit risk exposure as the replacement cost for open energy commodity and derivative positions plus amounts owed from counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses where the Companies have a legally enforceable right of setoff. See "Credit Exposure" in Note J to the First Quarter Financial Statements.

Investment Risk

The Companies' investment risk relates to the investment of plan assets for their pension and other postretirement benefit plans. The Companies' current investment policy for pension plan assets includes investment targets of 60 percent equities and 40 percent fixed income and other securities. At March 31, 2012, the pension plan investments consisted of 63 percent equity and 37 percent fixed income and other securities.

Material Contingencies

For information concerning potential liabilities arising from the Companies' material contingencies, see Notes B, G, and H to the First Quarter Financial Statements.

Results of Operations

See "Results of Operations – Summary," above.

Results of operations reflect, among other things, the Companies' accounting policies and rate plans that limit the rates the Utilities can charge their customers. Under the revenue decoupling mechanisms currently applicable to CECONY's electric and gas businesses and O&R's electric and gas businesses in New York, the Utilities' delivery revenues generally will not be affected by changes in delivery volumes from levels assumed when rates were approved. Delivery revenues for CECONY's steam business and O&R's businesses

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in New Jersey and Pennsylvania are affected by changes in delivery volumes resulting from weather, economic conditions and other factors. See Note B to the First Quarter Financial Statements.

In general, the Utilities recover on a current basis the fuel, gas purchased for resale and purchased power costs they incur in supplying energy to their full-service customers. Accordingly, such costs do not generally affect the Companies' results of operations. Management uses the term "net revenues" (operating revenues less such costs) to identify changes in operating revenues that may affect the Companies' results of operations. Management believes that, although "net revenues" may not be a measure determined in accordance with accounting principles generally accepted in the United States of America, the measure facilitates the analysis by management and investors of the Companies' results of operations.

Con Edison's principal business segments are CECONY's regulated utility activities, O&R's regulated utility activities and Con Edison's competitive energy businesses. CECONY's principal business segments are its regulated electric, gas and steam utility activities. A discussion of the results of operations by principal business segment for the three months ended March 31, 2012 and 2011 follows. For additional business segment financial information, see Note I to the First Quarter Financial Statements.

Three Months Ended March 31, 2012 Compared with Three Months Ended March 31, 2011

The Companies' results of operations (which were discussed above under "Results of Operations – Summary") in 2012 compared with 2011 were:

	CECONY		O&R		Competitive Energy Businesses and Other (a)		Con Edison (b)	
(millions of dollars)	Increases (Decreases) Amount	Increases (Decreases) Percent	Increases (Decreases) Amount	Increases (Decreases) Percent	Increases (Decreases) Amount	Increases (Decreases) Percent	Increases (Decreases) Amount	Increases (Decreases) Percent
Operating revenues	$ (148)	(5.5)%	$ (31)	(12.9)%	$ (92)	(23.1)%	$ (271)	(8.1)%
Purchased power	(36)	(7.5)	(28)	(41.2)	(20)	(6.4)	(84)	(9.7)
Fuel	(68)	(38.6)	N/A	N/A	—	—	(68)	(38.6)
Gas purchased for resale	(94)	(35.7)	(13)	(33.3)	(5)	(83.3)	(112)	(36.4)
Operating revenues less purchased power, fuel and gas purchased for resale (net revenues)	50	2.8	10	7.5	(67)	(84.8)	(7)	(0.4)
Operations and maintenance	48	8.0	6	8.5	(3)	(10.0)	51	7.3
Depreciation and amortization	14	6.9	1	8.3	—	—	15	6.9
Taxes, other than income taxes	(10)	(2.3)	3	23.1	(1)	(20.0)	(8)	(1.7)
Operating income	(2)	(0.4)	—	—	(63)	Large	(65)	(10.4)
Other income less deductions	(3)	(60.0)	(1)	Large	(2)	(66.7)	(6)	(66.7)
Net interest expense	1	0.7	(2)	(20.0)	(1)	(14.3)	(2)	(1.3)
Income before income tax expense	(6)	(1.4)	1	3.4	(64)	Large	(69)	(14.3)
Income tax expense	(11)	(7.6)	—	—	(24)	Large	(35)	(20.7)
Net income for common stock	$ 5	1.8%	$ 1	5.3%	$ (40)	Large	$ (34)	(10.9)%

(a) Includes inter-company and parent company accounting.

(b) Represents the consolidated financial results of Con Edison and its businesses.

CECONY

	Three Months Ended March 31, 2012				Three Months Ended March 31, 2011				
(millions of dollars)	Electric	Gas	Steam	2012 Total	Electric	Gas	Steam	2011 Total	2012-2011 Variation
Operating revenues	$ 1,735	$ 563	$ 263	$ 2,561	$ 1,721	$ 663	$ 325	$ 2,709	$ (148)
Purchased power	432	—	15	447	464	—	19	483	(36)
Fuel	50	—	58	108	76	—	100	176	(68)
Gas purchased for resale	—	169	—	169	—	263	—	263	(94)
Net revenues	1,253	394	190	1,837	1,181	400	206	1,787	50
Operations and maintenance	517	82	46	645	459	103	35	597	48
Depreciation and amortization	173	29	16	218	161	27	16	204	14
Taxes, other than income taxes	339	62	29	430	344	66	30	440	(10)
Operating income	**$ 224**	**$ 221**	**$ 99**	**$ 544**	**$ 217**	**$ 204**	**$ 125**	**$ 546**	**$ (2)**

Electric

CECONY's results of electric operations for the three months ended March 31, 2012 compared with the 2011 period is as follows:

	Three Months Ended		
(millions of dollars)	March 31, 2012	March 31, 2011	Variation
Operating revenues	$ 1,735	$ 1,721	$ 14
Purchased power	432	464	(32)
Fuel	50	76	(26)
Net revenues	1,253	1,181	72
Operations and maintenance	517	459	58
Depreciation and amortization	173	161	12
Taxes, other than income taxes	339	344	(5)
Electric operating income	**$ 224**	**$ 217**	**$ 7**

CECONY's electric sales and deliveries, excluding off-system sales, for the three months ended March 31, 2012 compared with the 2011 period were:

	Millions of kWhs Delivered				Revenues in Millions			
	Three Months Ended				Three Months Ended			
Description	March 31, 2012	March 31, 2011	Variation	Percent Variation	March 31, 2012	March 31, 2011	Variation	Percent Variation
Residential/Religious (a)	2,411	2,664	(253)	(9.5)%	$ 588	$ 648	$ (60)	(9.3)%
Commercial/Industrial	2,384	2,860	(476)	(16.6)	440	561	(121)	(21.6)
Retail access customers	5,903	5,558	345	6.2	591	474	117	24.7
NYPA, Municipal Agency and other sales	2,690	2,774	(84)	(3.0)	125	117	8	6.8
Other operating revenues	—	—	—	—	(9)	(79)	70	88.6
Total	**13,388**	**13,856**	**(468)**	**(3.4)%**	**$ 1,735**	**$ 1,721**	**$ 14**	**0.8%**

(a) "Residential/Religious" generally includes single-family dwellings, individual apartments in multi-family dwellings, religious organizations and certain other not-for-profit organizations.

CECONY's electric operating revenues increased $14 million in the three months ended March 31, 2012 compared with the 2011 period due primarily to higher revenues from the electric rate plan ($73 million), offset in part by lower purchased power ($32 million) and fuel costs ($26 million). CECONY's revenues from electric sales are subject to a revenue decoupling mechanism, as a result of which delivery revenues generally are not affected by changes in delivery volumes from levels assumed when rates were approved. Other electric operating revenues generally reflect changes in regulatory assets and liabilities in accordance with the revenue decoupling mechanism and other provisions of the company's rate plan.

Electric delivery volumes in CECONY's service area decreased 3.4 percent in the three months ended March 31, 2012 compared with the 2011 period. After adjusting for variations, principally weather and billing days, electric delivery volumes in CECONY's service area decreased 0.8 percent in the three months ended March 31, 2012 compared with the 2011 period reflecting lower average use per customer.

CECONY's electric purchased power costs decreased $32 million in the three months ended March 31, 2012 compared with the 2011 period due to a decrease in purchased volumes ($51 million), offset by an increase in unit costs ($19 million). Electric fuel costs decreased $26 million in the three months ended March 31, 2012 compared with the 2011 period due to lower unit costs ($20 million) and sendout volumes from the company's electric generating facilities ($6 million).

CECONY's electric operating income increased $7 million in the three months ended March 31, 2012 compared with the 2011 period. The increase reflects primarily higher net revenues ($72 million, due primarily to the electric rate plan) and lower taxes, other than income taxes ($5 million, principally property taxes). The higher net revenues were offset by higher operations and maintenance costs ($58 million, due primarily to higher pension expense ($38 million), employees' health care costs ($6 million)), injuries and damages ($6 million) and higher depreciation and amortization ($12 million). See "Regulatory Assets and Liabilities" in Note B to the First Quarter Financial Statements.

Gas

CECONY's results of gas operations for the three months ended March 31, 2012 compared with the 2011 period is as follows:

	Three Months Ended		
(millions of dollars)	March 31, 2012	March 31, 2011	Variation
Operating revenues	$ 563	$ 663	$ (100)
Gas purchased for resale	169	263	(94)
Net revenues	394	400	(6)
Operations and maintenance	82	103	(21)
Depreciation and amortization	29	27	2
Taxes, other than income taxes	62	66	(4)
Gas operating income	**$ 221**	**$ 204**	**$ 17**

CECONY's gas sales and deliveries, excluding off-system sales, for the three months ended March 31, 2012 compared with the 2011 period were:

	Thousands of dths Delivered				Revenues in Millions			
	Three Months Ended				Three Months Ended			
Description	March 31, 2012	March 31, 2011	Variation	Percent Variation	March 31, 2012	March 31, 2011	Variation	Percent Variation
Residential	14,608	18,783	(4,175)	(22.2)%	$ 260	$ 326	$ (66)	(20.2)%
General	11,136	13,250	(2,114)	(16.0)	120	152	(32)	(21.1)
Firm transportation	21,759	24,096	(2,337)	(9.7)	159	144	15	10.4
Total firm sales and transportation	**47,503**	**56,129**	**(8,626)**	**(15.4)**	**539**	**622**	**(83)**	**(13.3)**
Interruptible sales (a)	2,142	3,562	(1,420)	(39.9)	18	36	(18)	(50.0)
NYPA	9,549	5,820	3,729	64.1	1	1	—	—
Generation plants	14,299	12,359	1,940	15.7	7	7	—	—
Other	7,498	7,687	(189)	(2.5)	12	19	(7)	(36.8)
Other operating revenues	—	—	—		(14)	(22)	8	36.4
Total	**80,991**	**85,557**	**(4,566)**	**(5.3)%**	**$ 563**	**$ 663**	**$ (100)**	**(15.1)%**

(a) Includes 171 and 984 thousands of dths for the 2012 and 2011 period, respectively, which are also reflected in firm transportation and other.

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CECONY's gas operating revenues decreased $100 million in the three months ended March 31, 2012 compared with the 2011 period due primarily to a decrease in gas purchased for resale costs ($94 million). CECONY's revenues from gas sales are subject to a weather normalization clause and a revenue decoupling mechanism as a result of which delivery revenues are generally not affected by changes in delivery volumes from levels assumed when rates were approved. Other gas operating revenues generally reflect changes in regulatory assets and liabilities in accordance with the company's rate plan.

CECONY's sales and transportation volumes for firm customers decreased 15.4 percent in the three months ended March 31, 2012 compared with the 2011 period. After adjusting for variations, principally weather and billing days, firm gas sales and transportation volumes in the company's service area increased 0.9 percent in the three months ended March 31, 2012.

CECONY's purchased gas cost decreased $94 million in the three months ended March 31, 2012 compared with the 2011 period due to lower sendout volumes ($69 million) and unit costs ($25 million).

CECONY's gas operating income increased $17 million in the three months ended March 31, 2012 compared with the 2011 period. The increase reflects primarily lower operations and maintenance costs ($21 million, due primarily to a decrease in the surcharge for New York State regulatory assessments ($12 million) and lower taxes, other than incomes taxes ($4 million, principally property taxes and local taxes), offset by lower net revenues ($6 million) and higher depreciation ($2 million).

Steam

CECONY's results of steam operations for the three months ended March 31, 2012 compared with the 2011 period is as follows:

	Three Months Ended		
(millions of dollars)	March 31, 2012	March 31, 2011	Variation
Operating revenues	$ 263	$ 325	$ (62)
Purchased power	15	19	(4)
Fuel	58	100	(42)
Net revenues	190	206	(16)
Operations and maintenance	46	35	11
Depreciation and amortization	16	16	—
Taxes, other than income taxes	29	30	(1)
Steam operating income	**$ 99**	**$ 125**	**$ (26)**

CECONY's steam sales and deliveries for the three months ended March 31, 2012 compared with the 2011 period were:

	Millions of Pounds Delivered				Revenues in Millions			
	Three Months Ended				Three Months Ended			
Description	March 31, 2012	March 31, 2011	Variation	Percent Variation	March 31, 2012	March 31, 2011	Variation	Percent Variation
General	245	334	(89)	(26.6)%	$ 12	$ 15	$ (3)	(20.0)%
Apartment house	2,072	2,593	(521)	(20.1)	71	83	(12)	(14.5)
Annual power	4,935	6,541	(1,606)	(24.6)	193	234	(41)	(17.5)
Other operating revenues	—	—	—	—	(13)	(7)	(6)	(85.7)
Total	**7,252**	**9,468**	**(2,216)**	**(23.4)%**	**$ 263**	**$ 325**	**$ (62)**	**(19.1)%**

CECONY's steam operating revenues decreased $62 million in the three months ended March 31, 2012 compared with the 2011 period due primarily to lower fuel costs ($42 million), the net change in rates under the steam rate plan ($14 million) and lower purchased power costs ($4 million). Other steam operating revenues generally reflect changes in regulatory assets and liabilities in accordance with the company's rate plan.

Steam sales and delivery volumes decreased 23.4 percent in the three months ended March 31, 2012 compared with the 2011 period reflecting milder winter weather. After adjusting for variations, principally weather and billing days, steam sales and deliveries decreased 1.2 percent in the three months ended March 31, 2012, reflecting lower average normalized use per customer.

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CECONY's steam fuel costs decreased $42 million in the three months ended March 31, 2012 compared with the 2011 period due to lower unit costs ($25 million) and sendout volumes ($17 million). Steam purchased power costs decreased $4 million in the three months ended March 31, 2012 compared with the 2011 period due to a decrease in unit costs ($2 million) and purchased volumes ($2 million).

Steam operating income decreased $26 million in the three months ended March 31, 2012 compared with the 2011 period. The decrease reflects primarily lower net revenues ($16 million) and higher operations and maintenance costs ($11 million, due primarily to higher pension expense ($16 million)), offset by lower taxes, other than income taxes ($1 million, principally local taxes).

Income Taxes

Income taxes decreased $11 million in the three months ended March 31, 2012 compared with the 2011 period due primarily to higher deductions for injuries and damages payments in the 2012 period.

O&R

	Three Months Ended March 31, 2012			Three Months Ended March 31, 2011			
(millions of dollars)	Electric	Gas	2012 Total	Electric	Gas	2011 Total	2012-2011 Variation
Operating revenues	$ 128	$ 82	$ 210	$ 149	$ 92	$ 241	$ (31)
Purchased power	40	—	40	68	—	68	(28)
Gas purchased for resale	—	26	26	—	39	39	(13)
Net revenues	88	56	144	81	53	134	10
Operations and maintenance	59	18	77	53	18	71	6
Depreciation and amortization	9	4	13	9	3	12	1
Taxes, other than income taxes	12	4	16	9	4	13	3
Operating income	**$ 8**	**$ 30**	**$ 38**	**$ 10**	**$ 28**	**$ 38**	**$ —**

Electric

O&R's results of electric operations for the three months ended March 31, 2012 compared with the 2011 period is as follows:

	Three Months Ended		
(millions of dollars)	March 31, 2012	March 31, 2011	Variation
Operating revenues	$ 128	$ 149	$ (21)
Purchased power	40	68	(28)
Net revenues	88	81	7
Operations and maintenance	59	53	6
Depreciation and amortization	9	9	—
Taxes, other than income taxes	12	9	3
Electric operating income	**$ 8**	**$ 10**	**$ (2)**

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O&R's electric sales and deliveries, excluding off-system sales, for the three months ended March 31, 2012 compared with the 2011 period were:

	Millions of kWhs Delivered				Revenues in Millions			
	Three Months Ended				Three Months Ended			
Description	March 31, 2012	March 31, 2011	Variation	Percent Variation	March 31, 2012	March 31, 2011	Variation	Percent Variation
Residential/Religious (a)	375	429	(54)	(12.6)%	$ 58	$ 74	$ (16)	(21.6)%
Commercial/Industrial	243	316	(73)	(23.1)	28	41	(13)	(31.7)
Retail access customers	689	625	64	10.2	37	33	4	12.1
Public authorities	28	25	3	12.0	2	3	(1)	(33.3)
Other operating revenues	—	—	—	—	3	(2)	5	Large
Total	**1,335**	**1,395**	**(60)**	**(4.3)%**	**$ 128**	**$ 149**	**$ (21)**	**(14.1)%**

(a) "Residential/Religious" generally includes single-family dwellings, individual apartments in multi-family dwellings, religious organizations and certain other not-for-profit organizations.

O&R's electric operating revenues decreased $21 million in the three months ended March 31, 2012 compared with the 2011 period due primarily to lower purchased power costs ($28 million). O&R's New York electric delivery revenues are subject to a revenue decoupling mechanism, as a result of which delivery revenues are generally not affected by changes in delivery volumes from levels assumed when rates were approved. O&R's electric sales in New Jersey and Pennsylvania are not subject to a decoupling mechanism, and as a result, changes in such volumes do impact such revenues. Other electric operating revenues generally reflect changes in regulatory assets and liabilities in accordance with the company's electric rate plan. See "Rate Agreements – O&R – Electric" in Note B to the First Quarter Financial Statements.

Electric delivery volumes in O&R's service area decreased 4.3 percent in the three months ended March 31, 2012 compared with the 2011 period. After adjusting for weather and other variations, electric delivery volumes in O&R's service area decreased 2.0 percent in the three months ended March 31, 2012 compared with the 2011 period.

Electric operating income decreased $2 million in the three months ended March 31, 2012 compared with the 2011 period. The decrease reflects primarily higher operations and maintenance costs ($6 million, due to higher pension expense and other postretirement costs) and taxes other than income taxes ($3 million, principally property taxes), offset by higher net revenues ($7 million).

Gas

O&R's results of gas operations for the three months ended March 31, 2012 compared with the 2011 period is as follows:

	Three Months Ended		
(millions of dollars)	March 31, 2012	March 31, 2011	Variation
Operating revenues	$ 82	$ 92	$ (10)
Gas purchased for resale	26	39	(13)
Net revenues	56	53	3
Operations and maintenance	18	18	—
Depreciation and amortization	4	3	1
Taxes, other than income taxes	4	4	—
Gas operating income	**$ 30**	**$ 28**	**$ 2**

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O&R's gas sales and deliveries, excluding off-system sales, for the three months ended March 31, 2012 compared with the 2011 period were:

	Thousands of dths Delivered				Revenues in Millions			
	Three Months Ended				Three Months Ended			
Description	March 31, 2012	March 31, 2011	Variation	Percent Variation	March 31, 2012	March 31, 2011	Variation	Percent Variation
Residential	2,856	3,774	(918)	(24.3)%	$ 39	$ 53	$ (14)	(26.4)%
General	561	737	(176)	(23.9)	7	9	(2)	(22.2)
Firm transportation	4,368	5,296	(928)	(17.5)	31	31	—	—
Total firm sales and transportation	**7,785**	**9,807**	**(2,022)**	**(20.6)**	**77**	**93**	**(16)**	**(17.2)**
Interruptible sales	1,309	1,311	(2)	(0.2)	1	1	—	—
Generation plants	—	98	(98)	Large	—	—	—	—
Other	339	399	(60)	(15.0)	—	—	—	—
Other gas revenues	—	—	—	—	4	(2)	6	Large
Total	**9,433**	**11,615**	**(2,182)**	**(18.8)%**	**$ 82**	**$ 92**	**$ (10)**	**(10.9)%**

O&R's gas operating revenues decreased $10 million in the three months ended March 31, 2012 compared with the 2011 period due primarily to the decrease in gas purchased for resale in 2012 ($13 million), offset in part by the gas rate plan.

Sales and transportation volumes for firm customers decreased 20.6 percent in the three months ended March 31, 2012 compared with the 2011 period. After adjusting for weather and other variations, total firm sales and transportation volumes increased 2.1 percent in the three months ended March 31, 2012 compared with the 2011 period. O&R's New York revenues from gas sales are subject to a weather normalization clause that moderates, but does not eliminate, the effect of weather-related changes on net income.

Gas operating income increased $2 million in the three months ended March 31, 2012 compared with the 2011 period. The increase reflects primarily higher net revenues ($3 million), offset by higher depreciation ($1 million).

Competitive Energy Businesses

The competitive energy businesses' results of operations for the three months ended March 31, 2012 compared with the 2011 period is as follows:

	Three Months Ended		
(millions of dollars)	March 31, 2012	March 31, 2011	Variation
Operating revenues	$ 310	$ 408	$ (98)
Purchased power	295	321	(26)
Gas purchased for resale	1	6	(5)
Net revenues	14	81	(67)
Operations and maintenance	27	30	(3)
Depreciation and amortization	2	2	—
Taxes, other than income taxes	5	5	—
Operating income	**$ (20)**	**$ 44**	**$ (64)**

The competitive energy businesses' operating revenues decreased $98 million in the three months ended March 31, 2012 compared with the 2011 period, due primarily to lower electric retail and wholesale revenues. Electric wholesale revenues decreased $39 million in the three months ended March 31, 2012 as compared with the 2011 period, due to lower sales volumes ($25 million) and unit prices ($14 million). Electric retail revenues decreased $63 million, due to lower per unit prices ($33 million) and sales volume ($30 million). Gross profit on electric retail revenues decreased due primarily to lower volumes, offset in part by higher unit gross margins. Net mark-to-market values decreased $69 million in the three months ended

March 31, 2012 as compared with the 2011 period, of which $77 million in losses are reflected in purchased power costs and $9 million in gains are reflected in revenues. Other revenues decreased $5 million in the three months ended March 31, 2012 as compared with the 2011 period due primarily to lower energy services revenue.

Purchased power costs decreased $26 million in the three months ended March 2012 compared with the 2011 period, due primarily to lower purchased power costs of $103 million and changes in mark-to-market values of $77 million. Purchased power costs decreased $103 million due to lower unit prices ($58 million) and volumes ($45 million). Operating income decreased $64 million in the three months ended March 31, 2012 compared with the 2011 period due primarily to net mark-to-market effects ($69 million), partially offset by higher revenue from solar generating facilities and wholesale gross profit.

Other

For Con Edison, "Other" includes inter-company eliminations relating to operating revenues and operating expenses.

Item 3: Quantitative and Qualitative Disclosures About Market Risk

For information about the Companies' primary market risks associated with activities in derivative financial instruments, other financial instruments and derivative commodity instruments, see "Financial and Commodity Market Risks," in Part I, Item 2 of this report, which information is incorporated herein by reference.

Item 4: Controls and Procedures

The Companies maintain disclosure controls and procedures designed to provide reasonable assurance that the information required to be disclosed in the reports that they submit to the Securities and Exchange Commission (SEC) is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the issuer's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. For each of the Companies, its management, with the participation of its principal executive officer and principal financial officer, has evaluated its disclosure controls and procedures as of the end of the period covered by this report and, based on such evaluation, has concluded that the controls and procedures are effective to provide such reasonable assurance. Reasonable assurance is not absolute assurance, however, and there can be no assurance that any design of controls or procedures would be effective under all potential future conditions, regardless of how remote.

There was no change in the Companies' internal control over financial reporting that occurred during the Companies' most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Companies' internal control over financial reporting.

The Utilities are undertaking a project with the objective of improving business processes and information systems. The Utilities expect the project to reduce costs, improve support of operating activities, reduce financial reporting risks, and simplify compliance activities. The focus of the project is the implementation of new financial and supply-chain enterprise resource planning information systems. The Utilities expect the project to enhance the processes used by employees to record financial transactions and analyze data; purchase materials and services and manage inventory; develop business plans and budgets and report financial and purchasing data. The project is reasonably likely to materially affect the Companies' internal control over financial reporting.

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Part II Other Information

Item 1: Legal Proceedings

For information about certain legal proceedings affecting the Companies, see Notes B, G and H to the financial statements in Part I, Item 1 of this report, which information is incorporated herein by reference.

Item 1A: Risk Factors

There were no material changes in the Companies' risk factors compared to those disclosed in Item 1A of the Form 10-K.

Item 2: Unregistered Sales of Equity Securities and Use of Proceeds

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares (or Units) Purchased*	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Appropriate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
January 1, 2012 to January 31, 2012	132,747	$ 59.33	—	—
February 1, 2012 to February 29, 2012	88,902	59.07	—	—
March 1, 2012 to March 31, 2012	99,494	58.22	—	—
Total	321,143	$ 58.91	—	—

* Represents Con Edison common shares purchased in open-market transactions. The number of shares purchased approximated the number of treasury shares used for the company's employee stock plans.

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Item 6: Exhibits
CON EDISON

Exhibit 12.1	Statement of computation of Con Edison's ratio of earnings to fixed charges for the three-month periods ended March 31, 2012 and 2011, and the 12-month period ended December 31, 2011.
Exhibit 31.1.1	Rule 13a-14(a)/15d-14(a) Certifications – Chief Executive Officer.
Exhibit 31.1.2	Rule 13a-14(a)/15d-14(a) Certifications – Chief Financial Officer.
Exhibit 32.1.1	Section 1350 Certifications – Chief Executive Officer.
Exhibit 32.1.2	Section 1350 Certifications – Chief Financial Officer.
Exhibit 101.INS	XBRL Instance Document.
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

CECONY

Exhibit 10.2	Amendment Number 4, dated January 1, 2011, to the Consolidated Edison Company of New York, Inc. 2005 Executive Incentive Plan.
Exhibit 12.2	Statement of computation of CECONY's ratio of earnings to fixed charges for the three-month periods ended March 31, 2012 and 2011, and the 12-month period ended December 31, 2011.
Exhibit 31.2.1	Rule 13a-14(a)/15d-14(a) Certifications – Chief Executive Officer.
Exhibit 31.2.2	Rule 13a-14(a)/15d-14(a) Certifications – Chief Financial Officer.
Exhibit 32.2.1	Section 1350 Certifications – Chief Executive Officer.
Exhibit 32.2.2	Section 1350 Certifications – Chief Financial Officer.
Exhibit 101.INS	XBRL Instance Document.
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Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	CONSOLIDATED EDISON, INC. **CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.**	
DATE: May 3, 2012	By	/s/ Robert Hoglund
		Robert Hoglund **Senior Vice President, Chief Financial Officer and Duly Authorized Officer**

Exhibit 12.1

Consolidated Edison, Inc.
Ratio of Earnings to Fixed Charges
(Millions of Dollars)

	For the Three Months Ended March 31, 2012	For the Twelve Months Ended December 31, 2011	For the Three Months Ended March 31, 2011
Earnings			
Net Income for Common Stock	$ 277	$ 1,051	$ 311
Preferred Stock Dividend	3	11	3
(Income) or Loss from Equity Investees	1	—	2
Minority Interest Loss	—	—	—
Income Tax	134	600	169
Pre-Tax Income for Common Stock	$ 415	$ 1,662	$ 485
Add: Fixed Charges*	161	642	165
Add: Distributed Income of Equity Investees	—	—	—
Subtract: Interest Capitalized	—	—	—
Subtract: Pre-Tax Preferred Stock Dividend Requirement	5	19	5
Earnings	**$ 571**	**$ 2,285**	**$ 645**
*** Fixed Charges**			
Interest on Long-term Debt	$ 141	$ 562	$ 141
Amortization of Debt Discount, Premium and Expense	4	20	6
Interest Capitalized	—	—	—
Other Interest	5	18	7
Interest Component of Rentals	6	23	6
Pre-Tax Preferred Stock Dividend Requirement	5	19	5
Fixed Charges	**$ 161**	**$ 642**	**$ 165**
Ratio of Earnings to Fixed Charges	3.5	3.6	3.9

Exhibit 31.1.1

CERTIFICATIONS

I, Kevin Burke, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012 of Consolidated Edison, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/ Kevin Burke

Kevin Burke
Chairman, President and Chief Executive Officer

Exhibit 31.1.2

CERTIFICATIONS

I, Robert Hoglund, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012 of Consolidated Edison, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/ Robert Hoglund

Robert Hoglund
Senior Vice President and Chief Financial Officer

Exhibit 32.1.1

Certification Required Under Section 906 of the Sarbanes-Oxley Act of 2002

I, Kevin Burke, the Chief Executive Officer of Consolidated Edison, Inc. (the "Company") certify that the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012, which this statement accompanies, (the "Form 10-Q") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)) and that the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Kevin Burke
Kevin Burke

Dated: May 3, 2012

Exhibit 32.1.2

Certification Required Under Section 906 of the Sarbanes-Oxley Act of 2002

I, Robert Hoglund, the Chief Financial Officer of Consolidated Edison, Inc. (the "Company") certify that the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012, which this statement accompanies, (the "Form 10-Q") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)) and that the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert Hoglund
Robert Hoglund

Dated: May 3, 2012

Exhibit 10.2

AMENDMENT #4

TO THE

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

2005 EXECUTIVE INCENTIVE PLAN

Effective January 1, 2011

Pursuant to the resolutions adopted by the Board of Directors of Consolidated Edison, Inc., at a meeting duly held on July 15, 2010, the undersigned hereby approves effective January 1, 2011, the amendment set forth below to the Consolidated Edison Company of New York, Inc. 2005 Executive Incentive Plan, as set forth below:

1. The **PURPOSE** is amended by adding the following at the end thereof:

   "Effective January 1, 2011, the Plan is amended to include language specifically stating that any Award granted to an Officer based on a performance period beginning on or after January 1, 2011 is subject to the Company's Recoupment Policy, as amended from time to time."

2. **ARTICLE V. PAYMENT OF AWARDS** is amended as follows:

   A new Section 5.04 is added as follows:

   5.04 Recoupment of Awards

   The Participant's Incentive Award, is subject to the Company's Recoupment Policy, as amended from time to time.

   (a) Under this Recoupment Policy, appropriate actions, as determined by the Committee, will be undertaken by the Company to recoup the Excess Award Amount, as defined below, received by any Participant when:

   (1) The Audit Committee of CEI determines that CEI is required to prepare an accounting restatement due to its material noncompliance with any financial reporting requirement under the securities laws (a "Restatement");

   (2) The Participant received an Award during the three-year period preceding the date on which CEI is required to prepare a Restatement; and

(3) The amount of the Award received by the Participant, based on the erroneous data, was in excess of what would have been paid to the Participant under the Restatement (the "Excess Award Amount").

IN WITNESS WHEREOF, the undersigned has executed this instrument this 29th day of February, 2012.

/s/ Mary Adamo

Plan Administrator,
Consolidated Edison Company of New York, Inc.
2005 Executive Incentive Plan
and
Vice President – Human Resources
Consolidated Edison Company of New York, Inc.

Exhibit 12.2

Consolidated Edison Company of New York, Inc.
Ratio of Earnings to Fixed Charges
(Millions of Dollars)

	For the Three Months Ended March 31, 2012	For the Twelve Months Ended December 31, 2011	For the Three Months Ended March 31, 2011
Earnings			
Net Income for Common Stock	$ 273	$ 978	$ 268
Preferred Stock Dividend	3	11	3
(Income) or Loss from Equity Investees	—	—	—
Minority Interest Loss	—	—	2
Income Tax	134	558	145
Pre-Tax Income for Common Stock	$ 410	$ 1,547	$ 418
Add: Fixed Charges*	141	561	142
Add: Distributed Income of Equity Investees	—	—	—
Subtract: Interest Capitalized	—	—	—
Subtract: Pre-Tax Preferred Stock Dividend Requirement	—	—	—
Earnings	**$ 551**	**$ 2,108**	**$ 560**
*** Fixed Charges**			
Interest on Long-term Debt	$ 127	$ 505	$ 126
Amortization of Debt Discount, Premium and Expense	4	18	6
Interest Capitalized	—	—	—
Other Interest	5	16	5
Interest Component of Rentals	5	22	5
Pre-Tax Preferred Stock Dividend Requirement	—	—	—
Fixed Charges	**$ 141**	**$ 561**	**$ 142**
Ratio of Earnings to Fixed Charges	3.9	3.8	3.9

Exhibit 31.2.1

CERTIFICATIONS

I, Kevin Burke, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012 of Consolidated Edison Company of New York, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/a/ Kevin Burke
Kevin Burke
Chairman and Chief Executive Officer

Exhibit 31.2.2

CERTIFICATIONS

I, Robert Hoglund, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012 of Consolidated Edison Company of New York, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/ Robert Hoglund

Robert Hoglund
Senior Vice President and Chief
Financial Officer

Exhibit 32.2.1

Certification Required Under Section 906 of the Sarbanes-Oxley Act of 2002

I, Kevin Burke, the Chief Executive Officer of Consolidated Edison Company of New York, Inc. (the "Company") certify that the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012, which this statement accompanies, (the "Form 10-Q") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)) and that the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Kevin Burke
Kevin Burke

Dated: May 3, 2012

Exhibit 32.2.2

Certification Required Under Section 906 of the Sarbanes-Oxley Act of 2002

I, Robert Hoglund, the Chief Financial Officer of Consolidated Edison Company of New York, Inc. (the "Company") certify that the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012, which this statement accompanies, (the "Form 10-Q") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)) and that the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert Hoglund
Robert Hoglund

Dated: May 3, 2012

TEG 10-Q 3/31/2012

Section 1: 10-Q (10-Q)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2012

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	Internal Revenue Service Employer Identification No.
1-11337	**INTEGRYS ENERGY GROUP, INC.** (A Wisconsin Corporation) 130 East Randolph Street Chicago, Illinois 60601-6207 (312) 228-5400	39-1775292

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Common stock, $1 par value,
78,287,906 shares outstanding at
April 26, 2012

INTEGRYS ENERGY GROUP, INC.

QUARTERLY REPORT ON FORM 10-Q
For the Quarter Ended March 31, 2012

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Commonly Used Acronyms in this Quarterly Report on Form 10-Q

AMRP	Accelerated Natural Gas Main Replacement Program
ASU	Accounting Standards Update
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
ICC	Illinois Commerce Commission
ICR	Infrastructure Cost Recovery
ITF	Integrys Transportation Fuels, LLC
LIFO	Last-in, First-out
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
MISO	Midwest Independent Transmission System Operator, Inc.
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utility Commission
N/A	Not Applicable
NSG	North Shore Gas Company
OCI	Other Comprehensive Income
PELLC	Peoples Energy, LLC (formerly known as Peoples Energy Corporation)
PGL	The Peoples Gas Light and Coke Company
PSCW	Public Service Commission of Wisconsin
SEC	United States Securities and Exchange Commission
UPPCO	Upper Peninsula Power Company
WDNR	Wisconsin Department of Natural Resources
WPS	Wisconsin Public Service Corporation

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Forward-Looking Statements

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are not guarantees of future results and conditions, but rather are subject to numerous management assumptions, risks, and uncertainties. Therefore, actual results may differ materially from those expressed or implied by these statements. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot provide assurance that such statements will prove correct.

Forward-looking statements involve a number of risks and uncertainties. Some risks that could cause actual results to differ materially from those expressed or implied in forward-looking statements include those described in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2011, as may be amended or supplemented in Part II, Item 1A of our subsequently filed Quarterly Reports on Form 10-Q (including this report), and those identified below:

- The timing and resolution of rate cases and related negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated businesses;
- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting coal-fired generation facilities and renewable energy standards;
- Other federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims, including manufactured gas plant site cleanup, third-party intervention in permitting and licensing projects, compliance with Clean Air Act requirements at generation plants, and prudence and reconciliation of costs recovered in revenues through automatic gas cost recovery mechanisms;
- Changes in credit ratings and interest rates caused by volatility in the financial markets and actions of rating agencies and their impact on our and our subsidiaries' liquidity and financing efforts;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the available sources of fuel, natural gas, and purchased power, including their impact on margins, working capital, and liquidity requirements;
- The timing and outcome of any audits, disputes, and other proceedings related to taxes;
- The effects, extent, and timing of additional competition or regulation in the markets in which our subsidiaries operate;
- The ability to retain market-based rate authority;
- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;
- The impact of unplanned facility outages;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer use, customer growth, and our ability to adequately forecast energy use for all of our customers;
- Potential business strategies, including mergers, acquisitions, and construction or disposition of assets or businesses, which cannot be assured to be completed timely or within budgets;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- The effectiveness of risk management strategies, the use of financial and derivative instruments, and the related recovery of these costs from customers in rates;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our and our subsidiaries' counterparties, affiliates, and customers to meet their obligations;
- Unusual weather and other natural phenomena, including related economic, operational, and/or other ancillary effects of any such events;
- The ability to use tax credit and loss carryforwards;
- The financial performance of ATC and its corresponding contribution to our earnings;
- The effect of accounting pronouncements issued periodically by standard-setting bodies; and
- Other factors discussed elsewhere herein and in other reports we file with the SEC.

Except to the extent required by the federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited) (Millions, except per share data)	Three Months Ended March 31 2012	 2011
Utility revenues	**$ 971.0**	$ 1,168.7
Nonregulated revenues	**280.3**	458.4
Total revenues	**1,251.3**	1,627.1
Utility cost of fuel, natural gas, and purchased power	**472.3**	660.7

Nonregulated cost of sales		**275.3**		404.0
Operating and maintenance expense		**261.0**		264.6
Depreciation and amortization expense		**62.7**		62.3
Taxes other than income taxes		**28.4**		26.8
Operating income		**151.6**		208.7
Earnings in equity method investments		**21.1**		19.4
Miscellaneous income		**2.4**		1.8
Interest expense		**(30.5)**		(34.8)
Other expense		**(7.0)**		(13.6)
Income before taxes		**144.6**		195.1
Provision for income taxes		**46.8**		71.7
Net income from continuing operations		**97.8**		123.4
Discontinued operations, net of tax		**1.9**		0.1
Net income		**99.7**		123.5
Preferred stock dividends of subsidiary		**(0.8)**		(0.8)
Net income attributed to common shareholders	**$**	**98.9**	$	122.7
Average shares of common stock				
Basic		**78.6**		78.3
Diluted		**79.2**		78.6
Earnings per common share (basic)				
Net income from continuing operations	**$**	**1.23**	$	1.57
Discontinued operations, net of tax		**0.03**		—
Earnings per common share (basic)	**$**	**1.26**	$	1.57
Earnings per common share (diluted)				
Net income from continuing operations	**$**	**1.22**	$	1.56
Discontinued operations, net of tax		**0.03**		—
Earnings per common share (diluted)	**$**	**1.25**	$	1.56
Dividends per common share declared	**$**	**0.68**	$	0.68

The accompanying condensed notes are an integral part of these statements.

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited) (Millions)	**Three Months Ended March 31**			
		2012		**2011**
Net income	**$**	**99.7**	$	123.5
Other comprehensive income, net of tax:				
Cash flow hedges				
Unrealized net losses arising during period, net of tax of $(0.2) million and $(2.4) million, respectively		**(0.3)**		(4.1)
Reclassification of net losses to net income, net of tax of $1.0 million and $5.1 million, respectively		**1.5**		8.4
Cash flow hedges, net		**1.2**		4.3
Defined benefit pension plans				
Amortization of pension and other postretirement costs included in net periodic benefit cost, net of tax of $0.3 million and $0.2 million, respectively		**0.3**		0.2
Other comprehensive income, net of tax		**1.5**		4.5
Comprehensive income		**101.2**		128.0
Less: preferred stock dividends of subsidiary		**(0.8)**		(0.8)
Comprehensive income attributed to common shareholders	**$**	**100.4**	$	127.2

The accompanying condensed notes are an integral part of these statements.

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited) (Millions)		March 31 2012		December 31 2011
Assets				
Cash and cash equivalents	$	42.3	$	28.1
Collateral on deposit		64.2		50.9
Accounts receivable and accrued unbilled revenues, net of reserves of $43.4 and $47.1, respectively		669.7		737.7
Inventories		125.1		252.3
Assets from risk management activities		266.2		227.2
Regulatory assets		132.8		125.1
Deferred income taxes		101.6		94.2
Prepaid taxes		144.3		209.6
Other current assets		87.5		78.2
Current assets		1,633.7		1,803.3
Property, plant, and equipment, net of accumulated depreciation of $3,057.7 and $3,018.7, respectively		5,259.0		5,199.1
Regulatory assets		1,655.4		1,658.5
Assets from risk management activities		56.6		64.4
Equity method investments		490.6		476.3
Goodwill		658.3		658.4
Other long-term assets		125.4		123.2
Total assets	$	9,879.0	$	9,983.2
Liabilities and Equity				
Short-term debt	$	305.5	$	303.3
Current portion of long-term debt		272.0		250.0
Accounts payable		331.2		426.6
Liabilities from risk management activities		400.0		311.6
Accrued taxes		75.4		70.5
Regulatory liabilities		96.5		67.5
Temporary LIFO liquidation credit		36.7		—
Other current liabilities		198.1		217.2
Current liabilities		1,715.4		1,646.7
Long-term debt		1,850.1		1,872.0
Deferred income taxes		1,108.7		1,070.7
Deferred investment tax credits		43.7		44.0
Regulatory liabilities		334.2		332.5
Environmental remediation liabilities		609.5		615.1
Pension and other postretirement benefit obligations		514.0		749.3
Liabilities from risk management activities		109.9		102.0
Asset retirement obligations		402.3		397.2
Other long-term liabilities		144.0		141.1
Long-term liabilities		5,116.4		5,323.9
Commitments and contingencies				
Common stock - $1 par value; 200,000,000 shares authorized; 78,287,906 shares issued; 77,916,543 shares outstanding		78.3		78.3
Additional paid-in capital		2,566.5		2,579.1
Retained earnings		409.2		363.6
Accumulated other comprehensive loss		(41.0)		(42.5)
Shares in deferred compensation trust		(17.0)		(17.1)
Total common shareholders' equity		2,996.0		2,961.4
Preferred stock of subsidiary - $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding		51.1		51.1
Noncontrolling interest in subsidiaries		0.1		0.1
Total liabilities and equity	$	9,879.0	$	9,983.2

The accompanying condensed notes are an integral part of these statements.

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited) (Millions)	Three Months Ended March 31 2012	2011
Operating Activities		
Net income	**$ 99.7**	$ 123.5
Adjustments to reconcile net income to net cash provided by operating activities		
Discontinued operations, net of tax	**(1.9)**	(0.1)
Depreciation and amortization expense	**62.7**	62.3
Recoveries and refunds of regulatory assets and liabilities	**9.5**	13.5
Net unrealized losses on nonregulated energy contracts	**44.7**	0.7
Bad debt expense	**10.1**	11.5
Pension and other postretirement expense	**17.6**	21.1
Pension and other postretirement contributions	**(246.6)**	(106.4)
Deferred income taxes and investment tax credits	**30.0**	67.2
Gain on sale of assets	**(0.2)**	(0.1)
Equity income, net of dividends	**(3.8)**	(3.0)
Other	**2.6**	10.2
Changes in working capital		
Collateral on deposit	**(13.7)**	(5.2)
Accounts receivable and accrued unbilled revenues	**49.9**	(50.1)
Inventories	**132.7**	152.7
Other current assets	**54.5**	28.3
Accounts payable	**(77.4)**	(23.8)
Temporary LIFO liquidation credit	**36.7**	119.2
Other current liabilities	**18.7**	(26.0)
Net cash provided by operating activities	**225.8**	395.5
Investing Activities		
Capital expenditures	**(123.0)**	(51.2)
Proceeds from the sale or disposal of assets	**1.4**	1.1
Capital contributions to equity method investments	**(10.4)**	(6.2)
Other	**(4.7)**	0.1
Net cash used for investing activities	**(136.7)**	(56.2)
Financing Activities		
Short-term debt, net	**2.2**	57.9
Repayment of long-term debt	**—**	(325.0)
Payment of dividends		
Preferred stock of subsidiary	**(0.8)**	(0.8)
Common stock	**(53.0)**	(47.4)
Issuance of common stock	**—**	7.2
Payments made on derivative contracts related to divestitures classified as financing activities	**(9.0)**	(11.1)
Other	**(14.3)**	(3.8)
Net cash used for financing activities	**(74.9)**	(323.0)
Net change in cash and cash equivalents	**14.2**	16.3
Cash and cash equivalents at beginning of period	**28.1**	179.0
Cash and cash equivalents at end of period	**$ 42.3**	$ 195.3

The accompanying condensed notes are an integral part of these statements.

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INTEGRYS ENERGY GROUP, INC. AND SUBSIDIARIES
CONDENSED NOTES TO FINANCIAL STATEMENTS
March 31, 2012

NOTE 1—FINANCIAL INFORMATION

As used in these notes, the term “financial statements” refers to the condensed consolidated financial statements. This includes the condensed consolidated statements of income, condensed consolidated statements of comprehensive income, condensed consolidated balance sheets, and condensed consolidated statements of cash flows, unless otherwise noted. In this report, when we refer to "us," "we," "our," or "ours," we are referring to Integrys Energy Group, Inc.

We prepare our financial statements in conformity with the rules and regulations of the SEC for Quarterly Reports on Form 10-Q and in accordance with GAAP. Accordingly, these financial statements do not include all of the information and footnotes required by GAAP for annual financial statements. These financial statements should be read in conjunction with the consolidated financial statements and footnotes in our Annual Report on Form 10-K for the year ended December 31, 2011.

In management's opinion, these unaudited financial statements include all adjustments considered necessary for a fair presentation of financial results. All adjustments are normal and recurring, unless otherwise noted. All intercompany transactions have been eliminated in consolidation. Financial results for an interim period may not give a true indication of results for the year.

NOTE 2—CASH AND CASH EQUIVALENTS

Short-term investments with an original maturity of three months or less are reported as cash equivalents.

The following is supplemental disclosure to our statements of cash flows:

	Three Months Ended March 31	
(Millions)	2012	2011
Cash paid for interest	**$ 8.9**	$ 20.1
Cash (received) paid for income taxes	**(33.2)**	2.9

Significant noncash transactions were:

	Three Months Ended March 31	
(Millions)	2012	2011
Construction costs funded through accounts payable	**$ 50.2**	$ 9.4
Equity issued for stock-based compensation plans	**—**	6.6
Equity issued for reinvested dividends	**—**	5.4

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NOTE 3—RISK MANAGEMENT ACTIVITIES

The following tables show our assets and liabilities from risk management activities:

		March 31, 2012	
(Millions)	Balance Sheet Presentation *	Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	**$ 5.2**	**$ 43.9**
Natural gas contracts	Long-term	**0.3**	**9.2**
Financial transmission rights (FTRs)	Current	**1.0**	**0.1**
Petroleum product contracts	Current	**0.4**	**—**
Coal contract	Current	**—**	**5.6**
Coal contract	Long-term	**—**	**7.8**
Cash flow hedges			
Natural gas contracts	Current	**—**	**1.2**
Natural gas contracts	Long-term	**—**	**0.2**
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	**121.2**	**120.4**
Natural gas contracts	Long-term	**22.3**	**20.7**
Electric contracts	Current	**138.2**	**228.6**
Electric contracts	Long-term	**34.0**	**72.0**
Foreign exchange contracts	Current	**0.2**	**0.2**
	Current	**266.2**	**400.0**
	Long-term	**56.6**	**109.9**
Total		**$ 322.8**	**$ 509.9**

* All derivatives are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and sales exception. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the

required criteria are no longer met. We classify assets and liabilities from risk management activities as current or long-term based upon the maturities of the underlying contracts.

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(Millions)	Balance Sheet Presentation *	December 31, 2011 Assets from Risk Management Activities	December 31, 2011 Liabilities from Risk Management Activities
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	$ 9.1	$ 35.4
Natural gas contracts	Long-term	0.1	8.2
FTRs	Current	2.3	0.1
Petroleum product contracts	Current	0.1	—
Coal contract	Current	—	2.5
Coal contract	Long-term	—	4.4
Cash flow hedges			
Natural gas contracts	Current	—	0.9
Natural gas contracts	Long-term	—	0.2
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	121.6	120.5
Natural gas contracts	Long-term	41.9	40.5
Electric contracts	Current	93.9	152.0
Electric contracts	Long-term	22.4	48.7
Foreign exchange contracts	Current	0.2	0.2
	Current	227.2	311.6
	Long-term	64.4	102.0
Total		$ 291.6	$ 413.6

* All derivatives are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and sales exception. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. We classify assets and liabilities from risk management activities as current or long-term based upon the maturities of the underlying contracts.

The following table shows our cash collateral positions:

(Millions)	March 31, 2012	December 31, 2011
Cash collateral provided to others	**$ 64.2**	$ 50.9
Cash collateral received from others *	**1.8**	2.3

* Reflected in other current liabilities on the balance sheets.

Certain of our derivative and nonderivative commodity instruments contain provisions that could require “adequate assurance” in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The following table shows the aggregate fair value of all derivative instruments with specific credit risk related contingent features that were in a liability position:

(Millions)	March 31, 2012	December 31, 2011
Integrys Energy Services	**$ 231.4**	$ 193.8
Utility segments	**52.9**	39.1

If all of the credit risk related contingent features contained in commodity instruments (including derivatives, nonderivatives, normal purchase and normal sales contracts, and applicable payables and receivables) had been triggered, our collateral requirement would have been as follows:

(Millions)	March 31, 2012	December 31, 2011
Collateral that would have been required:		
Integrys Energy Services	**$ 281.7**	$ 272.3
Utility segments	**42.5**	28.7
Collateral already satisfied:		
Integrys Energy Services — Letters of credit	**11.0**	11.0
Collateral remaining:		
Integrys Energy Services	**270.7**	261.3
Utility segments	**42.5**	28.7

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Utility Segments

Non-Hedge Derivatives

Utility derivatives include natural gas purchase contracts, a coal purchase contract, financial derivative contracts (futures, options, and swaps), and FTRs used to manage electric transmission congestion costs. Both the electric and natural gas utility segments use futures, options, and swaps to manage the risks associated with the market price volatility of natural gas supply costs and the costs of gasoline and diesel fuel used by utility vehicles. The electric utility segment also uses oil futures and options to manage price risk related to coal transportation.

The utilities had the following notional volumes of outstanding non-hedge derivative contracts:

	March 31, 2012			December 31, 2011	
	Purchases	Sales	Other Transactions	Purchases	Other Transactions
Natural gas (millions of therms)	**755.5**	**0.3**	**N/A**	1,122.7	N/A
FTRs (millions of kilowatt-hours)	**N/A**	**N/A**	**1,911.0**	N/A	5,077.5
Petroleum products (barrels)	**51,872.0**	**N/A**	**N/A**	46,872.0	N/A
Coal contract (millions of tons)	**3.9**	**N/A**	**N/A**	4.1	N/A

The tables below show the unrealized gains (losses) recorded related to non-hedge derivatives at the utilities:

		Three Months Ended March 31	
(Millions)	Financial Statement Presentation	2012	2011
Natural gas contracts	Balance Sheet — Regulatory assets (current)	**$ (6.4)**	$ 11.2
Natural gas contracts	Balance Sheet — Regulatory assets (long-term)	**(0.8)**	1.6
Natural gas contracts	Balance Sheet — Regulatory liabilities (current)	**(3.7)**	(0.1)
Natural gas contracts	Balance Sheet — Regulatory liabilities (long-term)	**0.1**	0.1
Natural gas contracts	Income Statement — Utility cost of fuel, natural gas, and purchased power	**0.1**	0.1
FTRs	Balance Sheet — Regulatory assets (current)	**0.4**	0.1
FTRs	Balance Sheet — Regulatory liabilities (current)	**(0.3)**	(1.2)
Petroleum product contracts	Balance Sheet — Regulatory assets (current)	**0.1**	—
Petroleum product contracts	Balance Sheet — Regulatory liabilities (current)	**0.1**	0.4
Petroleum product contracts	Income Statement — Operating and maintenance expense	**0.1**	0.5
Coal contract	Balance Sheet — Regulatory assets (current)	**(3.1)**	(0.5)
Coal contract	Balance Sheet — Regulatory assets (long-term)	**(3.5)**	(3.2)
Coal contract	Balance Sheet — Regulatory liabilities (long-term)	**—**	(3.7)

Nonregulated Segments

Non-Hedge Derivatives

Integrys Energy Services enters into derivative contracts such as futures, forwards, options, and swaps, that are used to manage commodity price risk primarily associated with retail electric and natural gas customer contracts.

In the next 12 months, pre-tax losses of $0.9 million and $4.5 million related to the discontinued cash flow hedges of natural gas contracts and electric contracts, respectively, are expected to be recognized in earnings as the forecasted transactions occur. These amounts are expected to be offset by the settlement of the related nonderivative customer contracts.

Integrys Energy Services had the following notional volumes of outstanding non-hedge derivative contracts:

	March 31, 2012		December 31, 2011	
(Millions)	Purchases	Sales	Purchases	Sales
Commodity contracts				
Natural gas (therms)	**885.3**	**713.3**	959.2	797.1
Electric (kilowatt-hours)	**38,083.7**	**23,063.4**	34,405.7	20,374.0
Foreign exchange contracts (Canadian dollars)	**2.6**	**2.6**	4.2	4.2

Gains (losses) related to non-hedge derivatives are recognized currently in earnings, as shown in the tables below:

(Millions)	Income Statement Presentation	Three Months Ended March 31 2012	2011
Natural gas contracts	Nonregulated revenue	**$ 4.0**	$ 8.1
Natural gas contracts	Nonregulated revenue (reclassified from accumulated OCI) *	**(1.2)**	(0.3)
Electric contracts	Nonregulated revenue	**(68.6)**	(1.0)
Electric contracts	Nonregulated revenue (reclassified from accumulated OCI) *	**(0.7)**	0.2
Total		**$ (66.5)**	$ 7.0

* Represents amounts reclassified from accumulated OCI related to cash flow hedges that were dedesignated in prior periods.

Fair Value Hedges

At PELLC, an interest rate swap designated as a fair value hedge was used to hedge changes in the fair value of $50.0 million of the $325.0 million Series A 6.9% notes. The interest rate swap and the notes were settled in January 2011. The changes in the fair value of this hedge were recognized in earnings, as were the changes in fair value of the hedged item. Unrealized gains (losses) related to the fair value hedge and the related hedged item are shown in the table below:

(Millions)	Income Statement Presentation	Three Months Ended March 31, 2011
Interest rate swap	Interest expense	$ (0.9)
Debt hedged by swap	Interest expense	0.9
Total		$ —

Cash Flow Hedges

Prior to July 1, 2011, Integrys Energy Services designated derivative contracts such as futures, forwards, and swaps as accounting hedges under GAAP. These contracts are used to manage commodity price risk associated with customer contracts.

The tables below show the amounts related to cash flow hedges recorded in OCI and in earnings:

Unrealized Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion)

(Millions)	Three Months Ended March 31, 2011
Natural gas contracts	$ 1.2
Electric contracts	(4.6)
Total	$ (3.4)

Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)

(Millions)	Income Statement Presentation	Three Months Ended March 31 2012	2011
Settled/Realized			
Natural gas contracts	Nonregulated revenue	**$ —**	$ (8.6)
Electric contracts	Nonregulated revenue	**—**	(4.1)
Interest rate swaps *	Interest expense	**(0.3)**	(0.3)
Hedge Designation Discontinued			
Natural gas contracts	Nonregulated revenue	**—**	(0.3)
Total		**$ (0.3)**	$ (13.3)

* In May 2010, we entered into interest rate swaps that were designated as cash flow hedges to hedge the variability in forecasted interest payments on a debt issuance. These swaps were terminated when the related debt was issued in November 2010. Amounts remaining in accumulated OCI are being reclassified to interest expense over the life of the related debt.

Gain Recognized in Income on Derivative Instruments
(Ineffective Portion and Amount Excluded from Effectiveness Testing)

(Millions)	Income Statement Presentation	Three Months Ended March 31, 2011
Natural gas contracts	Nonregulated revenue	**$ 0.8**

Electric contracts	Nonregulated revenue		**0.3**
Total		**$**	**1.1**

NOTE 4—DISCONTINUED OPERATIONS

Holding Company and Other Segment

During the three-month period ended March 31, 2012, we recorded a $1.9 million after-tax gain in discontinued operations at the holding company and other segment when we remeasured an unrecognized tax benefit liability that better reflects how the underlying uncertain tax positions are resolving themselves in various taxing jurisdictions.

Integrys Energy Services

During the three-month period ended March 31, 2011, Integrys Energy Services recorded a $0.1 million after-tax gain in discontinued operations when contingent payments were earned related to the 2009 sale of its energy management consulting business.

NOTE 5—INVESTMENT IN ATC

Our electric transmission investment segment consists of WPS Investments LLC's ownership interest in ATC, which was approximately 34% at March 31, 2012. ATC is a for-profit, transmission-only company regulated by FERC. ATC owns, maintains, monitors, and operates electric transmission assets in portions of Wisconsin, Michigan, Minnesota, and Illinois.

The following table shows changes to our investment in ATC.

(Millions)	Three Months Ended March 31 2012		2011	
Balance at the beginning of period	**$**	**439.4**	$	416.3
Add: Equity in net income		**20.8**		19.2
Add: Capital contributions		**3.4**		3.4
Less: Dividends received		**16.7**		16.2
Balance at the end of period	**$**	**446.9**	$	422.7

Financial data for all of ATC is included in the following tables:

(Millions)	Three Months Ended March 31 2012		2011	
Income statement data				
Revenues	**$**	**147.7**	$	139.6
Operating expenses		**69.6**		63.1
Other expense		**20.0**		22.3
Net income *	**$**	**58.1**	$	54.2

* As most income taxes are the responsibility of its members, ATC does not report a provision for its members' income taxes in its income statements.

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(Millions)	March 31, 2012		December 31, 2011	
Balance sheet data				
Current assets	**$**	**57.1**	$	58.7
Noncurrent assets		**3,099.0**		3,053.7
Total assets	**$**	**3,156.1**	$	3,112.4
Current liabilities	**$**	**314.5**	$	298.5
Long-term debt		**1,400.0**		1,400.0
Other noncurrent liabilities		**88.1**		82.6
Members' equity		**1,353.5**		1,331.3
Total liabilities and members' equity	**$**	**3,156.1**	$	3,112.4

NOTE 6—INVENTORIES

PGL and NSG price natural gas storage injections at the calendar year average of the cost of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of natural gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation debit or credit. Due to seasonality requirements, PGL and NSG expect interim reductions in LIFO layers to be replenished by year end.

NOTE 7—GOODWILL AND OTHER INTANGIBLE ASSETS

We had no material changes to the carrying amount of goodwill during the three months ended March 31, 2012, and 2011.

The identifiable intangible assets other than goodwill listed below are part of other current and long-term assets on the Balance Sheets.

(Millions)	March 31, 2012			December 31, 2011		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Customer-related (1)	**$ 34.5**	**$ (25.4)**	**$ 9.1**	$ 34.5	$ (24.8)	$ 9.7
Electric contract assets (2)	**—**	**—**	**—**	7.8	(6.6)	1.2
Patents (3)	**7.2**	**(0.1)**	**7.1**	7.2	—	7.2
Compressed natural gas fueling contract assets (4)	**5.6**	**(0.6)**	**5.0**	5.6	(0.3)	5.3
Renewable energy credits (5)	**3.3**	**—**	**3.3**	2.8	—	2.8
Nonregulated easements (6)	**3.8**	**(0.7)**	**3.1**	3.8	(0.7)	3.1
Customer-owned equipment modifications (7)	**3.8**	**(0.3)**	**3.5**	3.6	(0.2)	3.4
Emission allowances (8)	**1.6**	**(0.1)**	**1.5**	1.7	(0.2)	1.5
Other	**0.8**	**(0.3)**	**0.5**	1.4	(0.3)	1.1
Total	**$ 60.6**	**$ (27.5)**	**$ 33.1**	$ 68.4	$ (33.1)	$ 35.3
Unamortized intangible assets						
MGU trade name	**$ 5.2**	**—**	**$ 5.2**	$ 5.2	—	$ 5.2
Trillium trade name	**3.5**	**—**	**3.5**	3.5	—	3.5
Pinnacle trade name	**1.5**	**—**	**1.5**	1.5	—	1.5
Total intangible assets	**$ 70.8**	**$ (27.5)**	**$ 43.3**	$ 78.6	$ (33.1)	$ 45.5

(1) Includes customer relationship assets associated with PELLC's former nonregulated retail natural gas and electric operations, MERC's nonutility ServiceChoice business, and Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle) compressed natural gas fueling operations. The remaining weighted-average amortization period for customer-related intangible assets at March 31, 2012, was approximately 10 years.

(2) Represents electric customer contracts acquired in exchange for risk management assets.

(3) Includes the fair value of patents at Pinnacle related to a system for more efficiently compressing natural gas to allow for faster fueling. The remaining amortization period at March 31, 2012, was approximately 18 years.

(4) Represents the fair value of Trillium and Pinnacle compressed natural gas customer fueling contracts acquired in September 2011. The remaining amortization period at March 31, 2012, was approximately 9 years.

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(5) Used at Integrys Energy Services to comply with state Renewable Portfolio Standards and to support customer commitments.

(6) Relates to easements supporting a pipeline at Integrys Energy Services. The easements are amortized on a straight-line basis, with a remaining amortization period at March 31, 2012, of approximately 12 years.

(7) Relates to modifications to customer-owned equipment that allow the end-use customer of a pipeline to accept landfill gas. These intangible assets are amortized on a straight-line basis, with a remaining weighted-average amortization period at March 31, 2012, of approximately 12 years.

(8) Emission allowances do not have a contractual term or expiration date. If the EPA's Cross State Air Pollution Rule, which was stayed in December 2011, is reinstated, it will affect our ability to use certain existing emission allowances in the future. See Note 11, "*Commitments and Contingencies*," for more information.

Amortization expense recorded as a component of nonregulated cost of sales in the statements of income for the three months ended March 31, 2012, and 2011, was $1.6 million and $0.3 million, respectively.

Amortization expense recorded as a component of depreciation and amortization expense in the statements of income for the three months ended March 31, 2012, and 2011, was $0.7 million and $0.8 million, respectively.

Amortization expense for the next five fiscal years is estimated to be:

(Millions)	For the year ending December 31 2012	2013	2014	2015	2016
Amortization recorded in nonregulated cost of sales	$ 5.9	$ 1.8	$ 1.4	$ 1.3	$ 1.1
Amortization recorded in depreciation and amortization expense	2.5	2.0	1.7	1.7	1.5

NOTE 8—SHORT-TERM DEBT AND LINES OF CREDIT

Our short-term borrowings were as follows:

(Millions, except percentages)	March 31, 2012	December 31, 2011
Commercial paper outstanding	**$ 305.5**	$ 303.3
Average discount rate on outstanding commercial paper	**0.34%**	0.31%

The commercial paper outstanding at March 31, 2012, had maturity dates ranging from April 2, 2012, through April 30, 2012.

The table below presents our average amount of short-term borrowings outstanding based on daily outstanding balances during the three months ended March 31:

(Millions)	2012	2011
Average amount of commercial paper outstanding	**$ 357.5**	$ 102.7
Average amount of short-term notes payable outstanding	**—**	10.0

We manage our liquidity by maintaining adequate external financing commitments. The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing program, including remaining available capacity under these facilities:

(Millions)	Maturity	March 31, 2012	December 31, 2011
Revolving credit facility (Integrys Energy Group)	04/23/13	**$ 735.0**	$ 735.0
Revolving credit facility (Integrys Energy Group)	05/17/16	**200.0**	200.0
Revolving credit facility (Integrys Energy Group)	05/17/14	**275.0**	275.0
Revolving credit facility (WPS)	04/23/13	**115.0**	115.0
Revolving credit facility (WPS)	05/17/14	**135.0**	135.0
Revolving credit facility (PGL)	04/23/13	**250.0**	250.0
Total short-term credit capacity		**$ 1,710.0**	$ 1,710.0
Less:			
Letters of credit issued inside credit facilities		**$ 33.9**	$ 33.7
Commercial paper outstanding		**305.5**	303.3
Available capacity under existing agreements		**$ 1,370.6**	$ 1,373.0

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NOTE 9—LONG-TERM DEBT

(Millions)	March 31, 2012	December 31, 2011
WPS (1)	**$ 722.1**	$ 722.1
PGL	**525.0**	525.0
NSG (2)	**74.7**	74.7
Integrys Energy Group (3)	**774.8**	774.8
Other term loan (4)	**27.0**	27.0
Total	**2,123.6**	2,123.6
Unamortized discount	**(1.5)**	(1.6)
Total debt	**2,122.1**	2,122.0
Less current portion	**(272.0)**	(250.0)
Total long-term debt	**$ 1,850.1**	$ 1,872.0

(1) In December 2012, WPS's 4.875% Senior Notes will mature. As a result, the $150.0 million balance of these notes was included in current portion of long-term debt on our balance sheets.

In February 2013, WPS's 3.95% Senior Notes will mature. As a result, the $22.0 million balance of these notes was included in current portion of long-term debt on our March 31, 2012 balance sheet.

(2) In April 2012, NSG bought back its $28.2 million of 5.00% Series M First Mortgage Bonds that were due December 1, 2028.

In the same month, NSG issued $28.0 million of 3.43% Series P First Mortgage Bonds. These bonds are due April 1, 2027.

(3) In December 2012, our 5.375% Unsecured Senior Notes will mature. As a result, the $100.0 million balance of these notes was included in current portion of long-term debt on our balance sheets.

(4) This loan has a floating interest rate that is reset weekly. At March 31, 2012, the interest rate was 0.20%. The loan is to be repaid by April 2021.

NOTE 10—INCOME TAXES

We calculate our interim period provision for income taxes based on our projected annual effective tax rate as adjusted for certain discrete items.

The table below shows our effective tax rates:

	Three Months Ended March 31	
	2012	**2011**
Effective Tax Rate	**32.4%**	36.8%

Our effective tax rate for the three months ended March 31, 2012, was lower than the federal statutory tax rate of 35%. This difference primarily related to the federal income tax benefit of tax credits related to wind production and a remeasurement of an unrecognized tax benefit liability that better reflects how the underlying uncertain tax positions are resolving themselves in various taxing jurisdictions. Other state income tax obligations partially offset the lower effective tax rate.

Our effective tax rate for the three months ended March 31, 2011, was higher than the federal statutory tax rate of 35%. This difference primarily related to state income tax obligations, partially offset by tax credits related to wind production, along with other tax credits.

During the three months ended March 31, 2012, we remeasured and decreased our liability for unrecognized tax benefits by $2.7 million that better reflects how the underlying uncertain tax positions are resolving themselves in various taxing jurisdictions. We reduced the provision for income taxes related to this remeasurement, of which a portion was reported as discontinued operations.

NOTE 11—COMMITMENTS AND CONTINGENCIES

Commodity Purchase Obligations and Purchase Order Commitments

We and our subsidiaries routinely enter into long-term purchase and sale commitments for various quantities and lengths of time. The regulated natural gas utilities have obligations to distribute and sell natural gas to their customers, and the regulated electric utilities have obligations to distribute and sell electricity to their customers. The utilities expect to recover costs related to these obligations in future customer rates. Additionally, the majority of the energy supply contracts entered into by Integrys Energy Services are to meet its obligations to deliver energy to customers.

The purchase obligations described below were as of March 31, 2012.

- The electric utility segment had obligations of $186.3 million related to coal supply and transportation that extend through 2016, obligations of $1,213.9 million for either capacity or energy related to purchased power that extend through 2029, and obligations of $5.4 million for other commodities that extend through 2013.
- The natural gas utility segment had obligations of $836.7 million related to natural gas supply and transportation contracts that extend through 2028.
- Integrys Energy Services had obligations of $218.9 million, primarily related to electricity and natural gas supply contracts that extend through 2021.
- We and our subsidiaries also had commitments of $536.1 million in the form of purchase orders issued to various vendors that relate to normal business operations, including construction projects.

Environmental

Clean Air Act (CAA) New Source Review Issues

Weston and Pulliam Plants:

In November 2009, the EPA issued a Notice of Violation (NOV) to WPS alleging violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009. WPS continues to meet with the EPA and exchange proposals on a possible resolution. We are currently unable to estimate the possible loss or range of loss related to this matter.

In May 2010, WPS received from the Sierra Club a Notice of Intent (NOI) to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. WPS is working on a possible resolution with the Sierra Club and the EPA. We are currently unable to estimate the possible loss or range of loss related to this matter.

Columbia and Edgewater Plants:

In December 2009, the EPA issued an NOV to Wisconsin Power and Light (WP&L), the operator of the Columbia and Edgewater plants, and the other joint owners of these plants (including WPS). The NOV alleges violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WP&L and the other joint owners exchanged proposals with the EPA on a possible resolution. We are currently unable to estimate the possible loss or range of loss related to this matter.

In September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Columbia plant did not comply with the CAA. While the previous stay has been lifted and the case is moving forward to a December 2012 trial, the Sierra Club continues to participate in settlement negotiations with the EPA and the joint owners of the Columbia plant to seek resolution. We are currently unable to estimate the possible loss or range of loss related to this matter.

In September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Edgewater plant did not comply with the CAA. The previous stay of this case has been extended until July 15, 2012, and settlement negotiations with the Sierra Club, the EPA, and the joint owners of the Edgewater plant continue. We are currently unable to estimate the possible loss or range of loss related to this matter.

EPA Settlements with Other Utilities:

In response to the EPA's CAA enforcement initiative, several utilities elected to settle with the EPA, while others are in litigation. The fines, penalties, and costs of supplemental beneficial environmental projects associated with settlements involving comparably-sized facilities to Weston and Pulliam combined ranged between $6 million and $30 million. The regulatory interpretations upon which the lawsuits or settlements are based may change depending on future court decisions made in the pending litigation.

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If it were settled or determined that historical projects at the Weston, Pulliam, Columbia, and Edgewater plants required either a state or federal CAA permit, WPS may, under the applicable statutes, be required to complete the following remedial steps:

- shut down the facility,
- install additional pollution control equipment and/or impose emission limitations, and/or
- conduct a supplemental beneficial environmental project.

In addition, WPS may also be required to pay a fine. Finally, under the CAA, citizen groups may pursue a claim.

Weston Air Permits

Weston 4 Construction Permit:

From 2004 to 2009, the Sierra Club filed various petitions objecting to the construction permit issued for the Weston 4 plant. In June 2010, the Wisconsin Court of Appeals affirmed the Weston 4 construction permit, but directed the WDNR to reopen the permit to set specific visible emissions limits. In July 2010, the WDNR, WPS, and the Sierra Club filed Petitions for Review with the Wisconsin Supreme Court. In March 2011, the Wisconsin Supreme Court denied all Petitions for Review. Other than the specific visible emissions limits issue, all other challenges to the construction permit are now resolved. WPS is working with the WDNR and the Sierra Club to resolve this issue. We do not expect this matter to have a material impact on our financial statements.

Weston Title V Air Permit:

In November 2010, the WDNR provided a draft revised permit. WPS objected to proposed changes in mercury limits and requirements on the boilers as beyond the authority of the WDNR. WPS and the WDNR continue to meet to resolve these issues. In September 2011, the WDNR issued a draft revised permit and a request for public comments. WPS filed comments objecting to certain provisions in the draft permit. We do not expect this matter to have a material impact on our financial statements.

WDNR Issued NOVs:

Since 2008, WPS received four NOVs from the WDNR alleging various violations of the different air permits for the entire Weston plant, Weston 4, Weston 1, and Weston 2, as well as one NOV for a clerical error involving pages missing from a quarterly report for Weston. Corrective actions have been taken for the events in the five NOVs. In December 2011, the WDNR dismissed two of the NOVs and referred the other three NOVs to the state Justice Department for enforcement. We do not expect this matter to have a material impact on our financial statements.

Pulliam Title V Air Permit

The WDNR issued the renewal of the permit for the Pulliam plant in April 2009. In June 2010, the EPA issued an order directing the WDNR to respond to comments raised by the Sierra Club in its June 2009 Petition objecting to this permit.

WPS also challenged the permit in a contested case proceeding and Petition for Judicial Review. The Petition was dismissed in an order remanding the matter to the WDNR. In February 2011, the WDNR granted a contested case proceeding before an Administrative Law Judge on the issues raised by WPS, which included averaging times in the emission limits in the permit. WPS participated in the contested case proceeding in October 2011. In December 2011, the Administrative Law Judge did not require the WDNR to insert averaging times, for which WPS had argued. WPS has decided not to appeal.

In October 2010, WPS received from the Sierra Club a copy of an NOI to file a civil lawsuit against the EPA based on what the Sierra Club alleges to be the EPA's unreasonable delay in performing its duties related to the grant or denial of the permit. WPS received notification that the Sierra Club filed suit against the EPA in April 2011. WPS intervened in the case as a necessary party to protect its interests. The WDNR sent the proposed permit to the EPA for a 45-day review, which allowed the parties to enter into a settlement agreement that has not yet been entered by the court.

We are reviewing all of these matters, but we do not expect them to have a material impact on our financial statements.

Columbia Title V Air Permit

In October 2009, the EPA issued an order objecting to the permit renewal issued by the WDNR for the Columbia plant. The order determined that the WDNR did not adequately analyze whether a project in 2006 constituted a "major modification that required a permit." The EPA's order directed the WDNR to resolve the objections within 90 days and "terminate, modify, or revoke and reissue" the permit accordingly.

In July 2010, WPS, along with its co-owners, received from the Sierra Club a copy of an NOI to file a civil lawsuit against the EPA. The Sierra Club alleges that the EPA should assert jurisdiction over the permit because the WDNR failed to respond to the EPA's objection within 90 days.

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In September 2010, the WDNR issued a draft construction permit and a draft revised Title V permit in response to the EPA's order. In November 2010, the EPA notified the WDNR that the EPA "does not believe the WDNR's proposal is responsive to the order." In January 2011, the WDNR issued a letter stating that upon review of the submitted public comments, the WDNR has determined not to issue the draft permits that were proposed to respond to the EPA's order. In February 2011, the Sierra Club filed for a declaratory action, claiming that the EPA had to assert jurisdiction over the permits. In May 2011, the WDNR issued a second draft Title V permit in response to the EPA's order. WPS is monitoring this situation with WP&L and meeting with the WDNR. We do not expect this matter to have a material impact on our financial statements.

Mercury and Interstate Air Quality Rules

Mercury:

The State of Wisconsin's mercury rule, Chapter NR 446, requires a 40% reduction from the 2002 through 2004 baseline mercury emissions in Phase I, beginning January 1, 2010, through the end of 2014. In Phase II, which begins in 2015, electric generating units above 150 megawatts will be required to reduce mercury emissions by 90%. Reductions can be phased in and the 90% target delayed until 2021 if additional sulfur dioxide and nitrogen oxide reductions are implemented. By 2015, electric generating units above 25 megawatts but less than 150 megawatts must reduce their mercury emissions to a level defined by the Best Available Control Technology rule. As of March 31, 2012, WPS estimates capital costs of approximately $2 million, which includes estimates for both wholly owned and jointly owned plants, to achieve the required Phase I and Phase II reductions. The capital costs are expected to be recovered in future rate cases.

In December 2011, the EPA issued the final Utility Mercury and Air Toxics rule that will regulate emissions of mercury and other hazardous air pollutants. We are currently evaluating options for achieving the emission limits specified in this rule, but we do not anticipate the cost of compliance to be significant. We expect to recover future compliance costs in future rates.

Sulfur Dioxide and Nitrogen Oxide:

The EPA issued the Clean Air Interstate Rule (CAIR) in 2005 in order to reduce sulfur dioxide and nitrogen oxide emissions from utility boilers located in 29 states, including Wisconsin, Michigan, Pennsylvania, and New York. In July 2008, the United States Court of Appeals (Court of Appeals) issued a decision vacating CAIR, which the EPA appealed. In December 2008, the Court of Appeals reinstated CAIR and directed the EPA to address the deficiencies noted in its previous ruling to vacate CAIR. In July 2011, the EPA issued a final CAIR replacement rule known as the Cross State Air Pollution Rule (CSAPR). The new rule was to become effective January 1, 2012; however, on December 30, 2011, the D.C. Circuit Court (Court) issued a decision that stayed the rule pending the Court's resolution of the petitions for review. The Court directed the EPA to implement CAIR during the stay period. In January 2012, a briefing and oral argument schedule was set. Oral arguments were held on April 13, 2012. In comparison to the CAIR rule, CSAPR, in the version that was stayed, significantly reduced the emission allowances allocated to our subsidiaries' existing units for sulfur dioxide and nitrogen oxide in 2012, with a further reduction in 2014.

CSAPR also established new sulfur dioxide and nitrogen oxide emission allowances and did not allow carryover of the existing nitrogen oxide emission allowances allocated to WPS under CAIR. WPS did not acquire any CAIR nitrogen oxide emission allowances for 2012 and beyond other than those directly allocated to it, which were free. Sulfur dioxide emission allowances allocated under the Acid Rain Program will continue to be issued and surrendered independent of the stayed CSAPR emission allowance program. Thus, we do not expect any material impact on our financial statements as a result of being unable to carry over existing emission allowances.

Under CAIR, units affected by the Best Available Retrofit Technology (BART) rule are considered in compliance with BART for sulfur dioxide and nitrogen oxide emissions if they are in compliance with CAIR. Although particulate emissions also contribute to visibility impairment, the WDNR's modeling has shown the impairment to be so insignificant that additional capital expenditures on controls are not warranted. The EPA has proposed that units in compliance with CSAPR, if the stay is lifted and CSAPR is reinstated, will also be considered in compliance with BART.

The Court may uphold CSAPR, invalidate CSAPR, or direct the EPA to make changes to CSAPR. In order to be in compliance with the stayed version of CSAPR, additional sulfur dioxide and nitrogen oxide controls would need to be installed, emission allowances would need to be purchased, and/or our subsidiaries would have to make other changes to how they operate their existing units. The installation of any necessary controls will be scheduled as part of WPS's long-term maintenance plan for its existing units; however, WPS does not currently believe it could meet the stayed CSAPR's sulfur dioxide and nitrogen oxide emission limits without purchasing additional emission allowances or changing how its existing units are operated. Due to the uncertainty surrounding the rule, we are currently unable to predict whether, or if, additional emission allowances would be available to purchase or how much it would cost to comply. We are also currently unable to predict whether CSAPR, or any future version of CSAPR, will cause WPS to idle or abandon certain units or impact the estimated useful lives of certain units. WPS expects to recover any future compliance costs in future rates. The impact on Integrys Energy Services is not expected to be material.

Manufactured Gas Plant Remediation

Our natural gas utilities, their predecessors, and certain former affiliates operated facilities in the past at multiple sites for the purpose of manufacturing and storing manufactured gas. In connection with these activities, waste materials were produced that may have resulted in soil

and groundwater contamination at these sites. Under certain laws and regulations relating to the protection of the environment, our natural gas utilities are required to undertake remedial action with respect to some of these materials. They are coordinating the investigation and cleanup of the sites subject to EPA jurisdiction under what is called a "multi-site" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies.

Our natural gas utilities are responsible for the environmental remediation of 53 sites, of which 20 have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA's program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. As of March 31, 2012, we estimated and accrued for $608.1 million of future undiscounted investigation and cleanup costs for all sites. We may adjust these estimates in the future due to remedial technology, regulatory requirements, remedy determinations, and any claims of natural resource damages. As of March 31, 2012, cash expenditures for environmental remediation not yet recovered in rates were $15.6 million. We recorded a regulatory asset of $623.7 million at March 31, 2012, which is net of insurance recoveries received of $59.9 million, related to the expected recovery of both cash expenditures and estimated future expenditures through rates.

Management believes that any costs incurred for environmental activities relating to former manufactured gas plant operations that are not recoverable through contributions from other entities or from insurance carriers have been prudently incurred and are, therefore, recoverable through rates for WPS, MGU, PGL, and NSG. Accordingly, we do not expect these costs to have a material impact on our financial statements. However, any changes in the approved rate mechanisms for recovery of these costs, or any adverse conclusions by the various regulatory commissions with respect to the prudence of costs actually incurred, could materially affect rate recovery of such costs.

NOTE 12—GUARANTEES

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at March 31, 2012	Expiration: Less Than 1 Year	Expiration: 1 to 3 Years	Expiration: Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	**$ 623.9**	$ 407.7	$ 6.9	$ 209.3
Standby letters of credit (2)	**66.9**	35.3	31.5	0.1
Surety bonds (3)	**13.8**	13.8	—	—
Other guarantees (4)	**42.6**	20.0	—	22.6
Total guarantees	**$ 747.2**	$ 476.8	$ 38.4	$ 232.0

(1) Consists of parental guarantees of $456.2 million to support the business operations of Integrys Energy Services; $111.8 million and $48.9 million, respectively, related to natural gas supply at MERC and MGU; and $5.0 million at IBS, and $2.0 million at UPPCO to support business operations. These guarantees are not reflected on our balance sheets.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. This amount consists of $64.1 million issued to support Integrys Energy Services' operations and $2.8 million issued to support UPPCO, WPS, MGU, NSG, MERC, PGL, and Pinnacle CNG Systems. These amounts are not reflected on our balance sheets.

(3) Primarily for workers compensation self insurance programs and obtaining various licenses, permits, and rights of way. These guarantees

are not reflected on our balance sheets.

(4) Consists of (a) $20.0 million related to the sale agreement for Integrys Energy Services' United States wholesale electric marketing and trading business, which included a number of customary representations, warranties, and indemnification provisions. In addition, for a two-year period, counterparty payment default risk was retained with approximately 50% of the counterparties associated with the commodity contracts transferred in this transaction. An insignificant liability was recorded related to the fair value of this counterparty payment default risk; (b) $10.0 million related to the sale agreement for Integrys Energy Services' Texas retail marketing business, which included a number of customary representations, warranties, and indemnification provisions. An insignificant liability was recorded related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the tax law; (c) $5.0 million related to an environmental indemnification provided by Integrys Energy Services as part of the sale of the Stoneman generation facility, under which we expect that the likelihood of required performance is remote (this amount is not reflected on the balance sheets); and (d) $7.6 million related to other indemnifications primarily for workers compensation coverage. This amount is not reflected on our balance sheets.

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We have provided total parental guarantees of $559.0 million on behalf of Integrys Energy Services as shown in the table below. Our exposure under these guarantees related to existing transactions at March 31, 2012, was approximately $319.3 million.

(Millions)		March 31, 2012
Guarantees supporting commodity transactions	**$**	**456.2**
Standby letters of credit		**64.1**
Surety bonds		**3.2**
Other		**35.5**
Total guarantees	**$**	**559.0**

NOTE 13—EMPLOYEE BENEFIT PLANS

As of February 16, 2012, our defined benefit pension plans were closed to all new hires.

The following table shows the components of net periodic benefit cost (including amounts capitalized to our balance sheet) for our benefit plans for the three months ended March 31:

	Pension Benefits				Other Postretirement Benefits			
(Millions)		2012		2011		2012		2011
Service cost	**$**	**12.4**	$	11.3	**$**	**5.5**	$	5.0
Interest cost		**19.8**		20.5		**7.2**		7.7
Expected return on plan assets		**(27.1)**		(24.7)		**(7.0)**		(5.0)
Amortization of transition obligation		**—**		—		**0.1**		0.1
Amortization of prior service cost (credit)		**1.2**		1.3		**(0.9)**		(0.9)
Amortization of net actuarial loss		**8.3**		4.7		**1.6**		1.1
Net periodic benefit cost	**$**	**14.6**	$	13.1	**$**	**6.5**	$	8.0

Transition obligations, prior service costs (credits), and net actuarial losses that have not yet been recognized as a component of net periodic benefit cost are included in accumulated OCI for our nonregulated entities and are recorded as net regulatory assets for our utilities.

We make contributions to our plans in accordance with legal and tax requirements. These contributions do not necessarily occur evenly throughout the year. We contributed $171.5 million to our pension plans and $75.1 million to our other postretirement benefit plans during the three months ended March 31, 2012. We expect to contribute an additional $3.8 million to our pension plans and $39.1 million to our other postretirement benefit plans during the remainder of 2012, dependent upon various factors affecting us, including our liquidity position and tax law changes.

NOTE 14—STOCK-BASED COMPENSATION

The following table reflects the stock-based compensation expense and the related deferred tax benefit recognized in income for the three months ended March 31:

(Millions)		2012		2011
Performance stock rights	**$**	**1.2**	$	(0.7)
Restricted shares and restricted share units		**2.1**		2.2
Total stock-based compensation expense	**$**	**3.3**	$	1.5
Deferred income tax benefit	**$**	**1.3**	$	0.6

Compensation cost recognized for stock options during the three months ended March 31, 2012, and 2011, was not significant.

The total compensation cost capitalized for all awards during the three months ended March 31, 2012, and 2011, was not significant.

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Stock Options

The fair value of stock option awards granted is estimated using a binomial lattice model. The expected term of option awards is calculated based on historical exercise behavior and represents the period of time that options are expected to be outstanding. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. Our expected stock price volatility is estimated using its 10-year historical volatility. The following table shows the weighted-average fair value per stock option granted during the three months ended March 31, 2012, along with the assumptions incorporated into the valuation model:

	February 2012 Grant
Weighted-average fair value per option	**$ 6.30**
Expected term	**5 years**
Risk-free interest rate	**0.17% - 2.18%**
Expected dividend yield	**5.28%**
Expected volatility	**25%**

A summary of stock option activity for the three months ended March 31, 2012, and information related to outstanding and exercisable stock options at March 31, 2012, is presented below:

	Stock Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Life (in Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2011	2,953,630	$ 48.09		
Granted	**279,535**	**53.24**		
Exercised	**(225,986)**	**44.83**		
Outstanding at March 31, 2012	**3,007,179**	**$ 48.82**	**5.97**	**$ 14.2**
Exercisable at March 31, 2012	**2,221,968**	**$ 49.24**	**5.02**	**$ 9.9**

The aggregate intrinsic value for outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they all exercised their options at March 31, 2012. This is calculated as the difference between our closing stock price on March 31, 2012, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the three months ended March 31, 2012, and 2011, was $2.0 million and $0.6 million, respectively.

As of March 31, 2012, $2.6 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 3.2 years.

Cash received from option exercises during the three months ended March 31, 2012 was $10.1 million, and was not significant for the three months ended March 31, 2011. The actual tax benefit realized for the tax deductions from these option exercises was not significant for the three months ended March 31, 2012, and 2011.

Performance Stock Rights

The fair values of performance stock rights were estimated using a Monte Carlo valuation model. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. The expected volatility was estimated using one to three years of historical data. The table below reflects the assumptions used in the valuation of the outstanding grants at March 31:

	2012
Risk-free interest rate	**0.32% - 1.27%**
Expected dividend yield	**5.28% - 5.34%**
Expected volatility	**21% - 36%**

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A summary of the activity for the three months ended March 31, 2012, related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value*
Outstanding at December 31, 2011	135,948	$ 46.18
Granted	**18,865**	**52.70**
Distributed	**(70,598)**	**42.93**

Adjustment for final payout	**(24,804)**		**42.93**
Outstanding at March 31, 2012	**59,411**	**$**	**53.48**

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* Reflects the weighted-average fair value used to measure equity awards. Equity awards are measured using the grant date fair value or the fair value on the modification date for awards that have not been elected for deferral into the deferred compensation plan six months prior to the completion of the performance period.

A summary of the activity for the three months ended March 31, 2012, related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2011	186,215
Granted	**75,408**
Distributed	**(16,001)**
Adjustment for final payout	**(5,622)**
Outstanding at March 31, 2012	**240,000**

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of March 31, 2012, was $56.22 per performance stock right.

As of March 31, 2012, $5.7 million of compensation cost related to unvested and outstanding performance stock rights (equity and liability awards) was expected to be recognized over a weighted-average period of 2.3 years.

The total intrinsic value of performance stock rights distributed during the three months ended March 31, 2012, and 2011, was $4.7 million and $6.3 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance stock rights during the three months ended March 31, 2012, and 2011 was $1.9 million and $2.5 million, respectively.

Restricted Shares and Restricted Share Units

During the second quarter of 2011, the last of the outstanding restricted shares vested. Only restricted share units remain outstanding at March 31, 2012.

A summary of the activity related to all restricted share unit awards (equity and liability awards) for the three months ended March 31, 2012, is presented below:

	Restricted Share Unit Awards		Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2011	497,722	$	45.21
Granted	**188,346**		**53.24**
Dividend equivalents	**6,821**		**47.94**
Vested	**(193,878)**		**45.07**
Forfeited	**(1,440)**		**46.48**
Outstanding at March 31, 2012	**497,571**	**$**	**48.39**

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As of March 31, 2012, $16.7 million of compensation cost related to these awards was expected to be recognized over a weighted-average period of 3.1 years.

The total intrinsic value of restricted share and restricted share unit awards vested for the three months ended March 31, 2012, and 2011, was $10.4 million and $6.3 million, respectively. The actual tax benefit realized for the tax deductions from the vesting of restricted shares and restricted share units during the three months ended March 31, 2012, and 2011, was $4.2 million and $2.5 million, respectively.

The weighted-average grant date fair value of restricted share units awarded during the three months ended March 31, 2012, and 2011, was $53.24 and $49.40 per share, respectively.

NOTE 15—COMMON EQUITY

We had no changes to issued common stock during the three months ended March 31, 2012.

Beginning May 1, 2011, shares were purchased on the open market to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans.

The following table reconciles common shares issued and outstanding:

	March 31, 2012	December 31, 2011

	Shares	Average Cost	Shares	Average Cost
Common stock issued	**78,287,906**		78,287,906	
Less:				
Deferred compensation rabbi trust	**371,363**	**$ 45.71***	382,971	$ 44.54*
Total common shares outstanding	**77,916,543**		77,904,935	

* Based on our stock price on the day the shares entered the deferred compensation rabbi trust. Shares paid out of the trust are valued at the average cost of shares in the trust.

Earnings Per Share

Basic earnings per share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for shares we are obligated to issue under the deferred compensation and restricted share unit plans. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include in-the-money stock options, performance stock rights, restricted share units, and certain shares issuable under the deferred compensation plan. The calculation of diluted earnings per share for the three months ended March 31, 2012, and 2011, each excluded 0.8 million out-of-the-money stock options that had an anti-dilutive effect. The following table reconciles our computation of basic and diluted earnings per share:

	Three Months Ended March 31	
(Millions, except per share amounts)	**2012**	**2011**
Numerator:		
Net income from continuing operations	**$ 97.8**	$ 123.4
Discontinued operations, net of tax	**1.9**	0.1
Preferred stock dividends of subsidiary	**(0.8)**	(0.8)
Net income attributed to common shareholders	**$ 98.9**	$ 122.7
Denominator:		
Average shares of common stock — basic	**78.6**	78.3
Effect of dilutive securities		
Stock-based compensation	**0.4**	0.3
Deferred compensation	**0.2**	—
Average shares of common stock — diluted	**79.2**	78.6
Earnings per common share		
Basic	**$ 1.26**	$ 1.57
Diluted	**1.25**	1.56

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Accumulated Other Comprehensive Loss

The following table shows the changes to our accumulated other comprehensive loss from December 31, 2011 to March 31, 2012:

	Cash Flow Hedges	Defined Benefit Pension Plans	Accumulated Other Comprehensive Income (Loss)
Beginning balance at December 31, 2011	$ (11.5)	$ (31.0)	$ (42.5)
Current period other comprehensive income	**1.2**	**0.3**	**1.5**
Ending balance at March 31, 2012	**$ (10.3)**	**$ (30.7)**	**$ (41.0)**

Dividend Restrictions

Our ability as a holding company to pay dividends is largely dependent upon the availability of funds from our subsidiaries. Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our regulated utility subsidiaries to transfer funds to us in the form of dividends. Our regulated utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly.

The PSCW allows WPS to pay normal dividends on its common stock of no more than 103% of the previous year's common stock dividend. In addition, the PSCW currently requires WPS to maintain a calendar year average financial common equity ratio of 50.24% or higher. WPS must obtain PSCW approval if the payment of dividends would cause it to fall below this authorized level of common equity. Our right to receive dividends on the common stock of WPS is also subject to the prior rights of WPS's preferred shareholders and to provisions in WPS's restated articles of incorporation, which limit the amount of common stock dividends that WPS may pay if its common stock and common stock surplus accounts constitute less than 25% of its total capitalization.

NSG's long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of its capital stock.

PGL and WPS have short-term debt obligations containing financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default which could result in the acceleration of their outstanding debt obligations.

We also have short-term and long-term debt obligations that contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default which could result in the acceleration of outstanding debt obligations. At March 31, 2012, these covenants did not restrict the payment of any dividends beyond the amount restricted under our subsidiary requirements described above.

As of March 31, 2012, total restricted net assets were approximately $1,410.5 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was approximately $112.5 million at March 31, 2012.

We also have the option to defer interest payments on our outstanding Junior Subordinated Notes, from time to time, for one or more periods of up to ten consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, purchase, acquire, or make a liquidation payment on, any of our capital stock.

Except for the restrictions described above and subject to applicable law, we do not have any other significant dividend restrictions.

Capital Transactions with Subsidiaries

During the three months ended March 31, 2012, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
WPS	$ **26.4**	$ **—**	$ **40.0**
WPS Investments, LLC *	**16.7**	**—**	**3.4**
MERC	**—**	**15.0**	**—**
IBS	**—**	**3.0**	**—**
MGU	**—**	**6.0**	**—**
UPPCO	**—**	**2.5**	**8.5**
Total	$ **43.1**	$ **26.5**	$ **51.9**

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* WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us, WPS, and UPPCO. At March 31, 2012, WPS and UPPCO had a 12.17% and 2.59% ownership interest, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2012, all equity contributions to WPS Investments, LLC were made solely by us.

NOTE 16—VARIABLE INTEREST ENTITIES

In 2011, ITF formed Integrys PTI CNG Fuels LLC as a joint venture with Paper Transport Inc. ITF and Paper Transport Inc. each own 50% of the joint venture. The joint venture was established to own and operate compressed natural gas fueling stations. The preferred source of capital funding for the joint venture will be loans from ITF. We determined that the joint venture is a variable interest entity and that ITF is the primary beneficiary, which requires us to consolidate the assets, liabilities, and statements of income of the joint venture. At March 31, 2012, and December 31, 2011, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. Our maximum exposure to loss as a result of this joint venture was not significant. The carrying amounts of Integrys PTI CNG Fuels LLC assets and liabilities included on our balance sheets were insignificant.

We have variable interests in two entities through power purchase agreements relating to the cost of fuel. One of these purchased power agreements reimburses an independent power producing entity for coal costs relating to purchased energy. There is no obligation to purchase energy under the agreement. This contract expires in 2014. The other agreement contains a tolling arrangement in which we supply the scheduled fuel and purchase capacity and energy from the facility. This contract expires in 2016. As of March 31, 2012, and December 31, 2011, we had approximately 517.5 megawatts of capacity available under these agreements. We evaluated each of these variable interest entities for possible consolidation. We considered which interest holder has the power to direct the activities that most significantly impact the economics of the variable interest entity; this interest holder is considered the primary beneficiary of the entity and is required to consolidate the entity. For a variety of reasons, including qualitative factors such as the length of the remaining term of the contracts compared with the remaining lives of the plants and the fact that we do not have the power to direct the operations and maintenance of the facilities, we determined we are not the primary beneficiary of these variable interest entities. At March 31, 2012, and December 31, 2011, the assets and liabilities on the balance sheets that related to our involvement with these variable interest entities pertained to working capital accounts and represented the amounts we owed for current deliveries of power. We have not guaranteed any debt or provided any equity support, liquidity arrangements, performance guarantees, or other commitments associated with these contracts. There is not a significant potential exposure to loss as a result of involvement with the variable interest entities.

NOTE 17—FAIR VALUE

Fair Value Measurements

The following tables show assets and liabilities that were accounted for at fair value on a recurring basis, categorized by level within the fair value hierarchy:

	March 31, 2012			
(Millions)	Level 1	Level 2	Level 3	Total
Risk Management Assets				
Utility Segments				
Natural gas contracts	$ —	$ 5.5	$ —	$ 5.5
Financial transmission rights (FTRs)	—	—	1.0	1.0
Petroleum product contracts	0.4	—	—	0.4
Nonregulated Segments				
Natural gas contracts	41.5	90.9	11.1	143.5
Electric contracts	61.3	96.8	14.1	172.2
Foreign exchange contracts	—	0.2	—	0.2
Total Risk Management Assets	$ 103.2	$ 193.4	$ 26.2	$ 322.8
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$ 1.6	$ 52.9	$ —	$ 54.5
FTRs	—	—	0.1	0.1
Coal contract	—	—	13.4	13.4
Nonregulated Segments				
Natural gas contracts	47.7	93.2	0.2	141.1
Electric contracts	81.2	183.4	36.0	300.6
Foreign exchange contracts	0.2	—	—	0.2
Total Risk Management Liabilities	$ 130.7	$ 329.5	$ 49.7	$ 509.9

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	December 31, 2011			
(Millions)	Level 1	Level 2	Level 3	Total
Risk Management Assets				
Utility Segments				
Natural gas contracts	$ 0.1	$ 9.1	$ —	$ 9.2
FTRs	—	—	2.3	2.3
Petroleum product contracts	0.1	—	—	0.1
Nonregulated Segments				
Natural gas contracts	50.7	104.1	8.7	163.5
Electric contracts	41.2	71.2	3.9	116.3
Foreign exchange contracts	—	0.2	—	0.2
Total Risk Management Assets	$ 92.1	$ 184.6	$ 14.9	$ 291.6
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$ 5.5	$ 39.2	$ —	$ 44.7
FTRs	—	—	0.1	0.1
Coal contract	—	—	6.9	6.9
Nonregulated Segments				
Natural gas contracts	55.0	105.6	0.4	161.0
Electric contracts	54.2	131.1	15.4	200.7
Foreign exchange contracts	0.2	—	—	0.2
Total Risk Management Liabilities	$ 114.9	$ 275.9	$ 22.8	$ 413.6

The risk management assets and liabilities listed in the tables include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices and interest rates. For more information on derivative instruments, see Note 3, "*Risk Management Activities*."

The following tables show net risk management assets (liabilities) transferred between the levels of the fair value hierarchy:

Nonregulated Segments — Electric Contracts

Three Months Ended March 31, 2012	Three Months Ended March 31, 2011

(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$ —**	**$ —**	N/A	$ —	$ —
Transfers into Level 2 from	**$ —**	**N/A**	**(0.1)**	$ —	N/A	(2.4)
Transfers into Level 3 from	**—**	**(5.0)**	**N/A**	—	(5.4)	N/A

Nonregulated Segments — Natural Gas Contracts

	Three Months Ended March 31, 2012			Three Months Ended March 31, 2011		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$ —**	**$ —**	N/A	$ —	$ —
Transfers into Level 2 from	**$ —**	**N/A**	**1.3**	$ —	N/A	0.4
Transfers into Level 3 from	**—**	**2.4**	**N/A**	—	(0.1)	N/A

Derivatives are transferred between the levels of the fair value hierarchy primarily due to changes in the source of data used to construct price curves as a result of changes in market liquidity. We recognize transfers between the levels of the fair value hierarchy at the value as of the end of the reporting period.

We determine fair value using a market-based approach that uses observable market inputs where available, and internally developed inputs where observable market data is not readily available. For the unobservable inputs, consideration is given to the assumptions that market participants would use in valuing the asset or liability. These factors include not only the credit standing of the counterparties involved, but also the impact of our nonperformance risk on our liabilities.

When possible, we base the valuations of our risk management assets and liabilities on quoted prices for identical assets in active markets. These valuations are classified in Level 1. The valuations of certain contracts include inputs related to market price risk (commodity or interest rate), price volatility (for option contracts), price correlation (for cross commodity contracts), probability of default, and time value. These inputs are available through multiple sources, including brokers and over-the-counter and online exchanges. Transactions valued using these inputs are classified in Level 2.

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Certain derivatives are categorized in Level 3 due to the significance of unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- While forward price curves may have been based on observable information, significant assumptions may have been made regarding monthly shaping and locational basis differentials.
- Certain transactions were valued using price curves that extended beyond an observable period. Assumptions were made to extrapolate prices from the last observable period through the end of the transaction term, primarily through the use of historically settled data or correlations to other locations.

We conduct a thorough review of fair value hierarchy classifications on a quarterly basis.

We have established risk oversight committees whose primary responsibility includes directly or indirectly ensuring that all valuation methods are applied in accordance with predefined policies. The development and maintenance of our forward price curves has been assigned to our risk management department, which is part of the corporate treasury function. This group is separate and distinct from any of the trading functions within the organization. To validate the reasonableness of our fair value inputs, our risk management department compares changes in valuation and researches any significant differences in order to determine the underlying cause. Corrections to the fair value inputs are made if necessary.

The significant unobservable inputs used in the valuation that resulted in categorization within Level 3 were as follows at March 31, 2012. The amounts and percentages listed in the table below represent the range of unobservable inputs that individually had a significant impact on the fair value determination and caused a derivative transaction to be classified as Level 3.

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
Utility Segments					
FTRs	**$ 1.0**	**$ 0.1**	Market-based	Forward market prices ($/megawatt-month) (1)	170.36
Coal contract	**—**	**13.4**	Market-based	Forward market prices ($/ton) (2)	14.6 –15.1
Nonregulated Segments					
Natural gas contracts	**11.1**	**0.2**	Market-based	Forward market prices ($/dekatherm) (3)	(0.04) –1.54
				Probability of default	11.62% - 50.99%
Electric contracts	**14.1**	**36.0**	Market-based	Forward market prices ($/megawatt-hours) (3)	(6.05) - 9.79
				Option volatilities (4)	19.99% - 59.51%
				Monthly curve shaping (5)	(15.03)% - (11.57)%

(1) Represents forward market prices developed using historical cleared pricing data from MISO used in the valuation of FTRs.

(2) Represents third-party forward market pricing used in the valuation of our coal contract.

(3) Represents unobservable basis spreads developed using historical settled prices that are applied to observable market prices at various natural gas and electric locations, as well as unobservable adjustments made to extend observable market prices beyond the quoted period through the end of the transaction term.

(4) Represents the range of volatilities used in the valuation of options.

(5) Represents adjustments made to forward market price curves to disaggregate average prices of multiple periods into discrete monthly prices.

Significant changes in historical settlement prices, forward commodity prices, and option volatilities would result in a directionally similar significant change in fair value. Significant changes in probability of default would result in a significant directionally opposite change in fair value. Changes in the adjustments to prices related to monthly curve shaping would affect fair value differently depending on their direction.

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The following tables set forth a reconciliation of changes in the fair value of items categorized as Level 3 measurements:

Three Months Ended March 31, 2012 (Millions)	Nonregulated Segments Natural Gas	Nonregulated Segments Electric	Utility Segments FTRs	Utility Segments Coal Contract	Total
Balance at the beginning of the period	**$ 8.3**	**$ (11.5)**	**$ 2.2**	**$ (6.9)**	**$ (7.9)**
Net realized and unrealized gains (losses) included in earnings	**4.1**	**(7.7)**	**0.5**	**—**	**(3.1)**
Net unrealized (losses) gains recorded as regulatory assets or liabilities	**—**	**—**	**0.1**	**(5.8)**	**(5.7)**
Purchases	**—**	**1.1**	**—**	**—**	**1.1**
Sales	**—**	**—**	**(0.1)**	**—**	**(0.1)**
Settlements	**(2.6)**	**1.1**	**(1.8)**	**(0.7)**	**(4.0)**
Net transfers into Level 3	**2.4**	**(5.0)**	**—**	**—**	**(2.6)**
Net transfers out of Level 3	**(1.3)**	**0.1**	**—**	**—**	**(1.2)**
Balance at the end of the period	**$ 10.9**	**$ (21.9)**	**$ 0.9**	**$ (13.4)**	**$ (23.5)**
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	**$ 4.1**	**$ (7.7)**	**$ —**	**$ —**	**$ (3.6)**

Three Months Ended March 31, 2011 (Millions)	Nonregulated Segments Natural Gas	Nonregulated Segments Electric	Utility Segments FTRs	Utility Segments Coal Contract	Total
Balance at the beginning of the period	$ 30.2	$ (14.9)	$ 2.9	$ 2.5	$ 20.7
Net realized and unrealized gains (losses) included in earnings	4.0	(2.9)	0.1	—	1.2
Net unrealized losses recorded as regulatory assets or liabilities	—	—	(1.1)	(7.0)	(8.1)
Net unrealized losses included in other comprehensive loss	—	(0.7)	—	—	(0.7)
Purchases	—	0.3	—	—	0.3
Sales	—	—	(0.1)	—	(0.1)
Settlements	(15.2)	2.5	(0.8)	(0.4)	(13.9)
Net transfers into Level 3	(0.1)	(5.4)	—	—	(5.5)
Net transfers out of Level 3	(0.4)	2.4	—	—	2.0
Balance at the end of the period	$ 18.5	$ (18.7)	$ 1.0	$ (4.9)	$ (4.1)
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$ 4.0	$ (2.9)	$ —	$ —	$ 1.1

Unrealized gains and losses included in earnings related to Integrys Energy Services' risk management assets and liabilities are recorded through nonregulated revenue on the statements of income. Realized gains and losses on these same instruments are recorded in nonregulated revenue or nonregulated cost of sales, depending on the nature of the instrument. Unrealized gains and losses on Level 3 derivatives at the utilities are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through utility cost of fuel, natural gas, and purchased power on the statements of income.

Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value:

(Millions)	March 31, 2012 Carrying Amount	March 31, 2012 Fair Value	December 31, 2011 Carrying Amount	December 31, 2011 Fair Value
Long-term debt	**$ 2,122.1**	**$ 2,272.2**	$ 2,122.0	$ 2,281.5
Preferred stock	**51.1**	**50.9**	51.1	51.8

The fair values of long-term debt instruments are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to us for debt of the same remaining maturity, without considering the effect of third-party credit enhancements. The fair values of preferred stock are estimated based on quoted market prices when available, or by using a perpetual dividend discount model. The fair values of long-term debt instruments and preferred stock are categorized within Level 2 of the fair value hierarchy.

Due to the short-term nature of cash and cash equivalents, accounts receivable, accounts payable, notes payable, and outstanding commercial paper, the carrying amount for each such item approximates fair value.

NOTE 18—ADVERTISING COSTS

At March 31, 2012, costs associated with certain natural gas and electric direct-response advertising campaigns at Integrys Energy Services were capitalized and reported as other long-term assets on the balance sheets. The capitalized costs result in probable future benefits and were incurred to solicit sales to customers who could be shown to have responded specifically to the advertising. The asset balances for each of the direct-response advertising cost pools are reviewed quarterly for impairment. Capitalized direct-response advertising costs, net of accumulated amortization, totaled $4.4 million as of March 31, 2012.

Direct-response advertising costs are amortized to operating and maintenance expense over the estimated period of benefit, which is approximately two years. The amortization of direct-response advertising costs was $1.0 million for the quarter ended March 31, 2012. There was no amortization of direct-response advertising costs for the quarter ended March 31, 2011.

We expense all advertising costs as incurred, except for those capitalized as direct-response advertising. Other advertising expense was $1.7 million and $1.9 million for the quarters ended March 31, 2012 and 2011, respectively.

NOTE 19—REGULATORY ENVIRONMENT

Wisconsin

2013 Rate Case

On March 30, 2012, WPS filed an application with the PSCW to increase retail electric and natural gas rates $85.1 million and $12.8 million, respectively, with rates proposed to be effective January 1, 2013. The filing includes a request for a 10.30% return on common equity and a common equity ratio of 52.37% in WPS's regulatory capital structure. The proposed retail electric and natural gas rate increases for 2013 are primarily being driven by reduced sales, increased fuel costs to generate electricity, increased electric transmission costs, increased costs to maintain the integrity of natural gas pipelines, increased manufactured gas plant cleanup costs, and general inflation.

2012 Rates

On December 9, 2011, the PSCW issued a final written order for WPS, effective January 1, 2012. It authorized an electric rate increase of $8.1 million and required a natural gas rate decrease of $7.2 million. The electric rate increase was driven by projected increases in fuel and purchased power costs. However, to the extent that actual fuel and purchased power costs exceed a 2% price variance from costs included in rates, they will be deferred for recovery or refund in a future rate proceeding. The rate order allows for the netting of the 2010 electric decoupling under-collection with the 2011 electric decoupling over-collection, and reflects reduced contributions to the Focus on Energy Program. The rate order also allows for the deferral of direct Cross State Air Pollution Rule (CSAPR) compliance costs, including carrying costs. As of March 31, 2012, WPS deferred $1.3 million of costs related to CSAPR.

2011 Rates

On January 13, 2011, the PSCW issued a final written order for WPS authorizing an electric rate increase of $21.0 million, calculated on a per unit basis. Although the rate order included a lower authorized return on common equity, lower rate base, and other reduced costs, which resulted in lower total revenues and margins, the rate order also projected lower total sales volumes, which led to a rate increase on a per-unit basis. The rate order also included a projected increase in customer counts that did not materialize, which impacts the decoupling calculation as it adjusts for differences between the actual and authorized margin per customer. The $21.0 million electric rate increase included $20.0 million of recovery of prior deferrals, the majority of which related to the recovery of the 2009 electric decoupling deferral. The $21.0 million excluded the impact of a $15.2 million estimated fuel refund (including carrying costs) from 2010. The PSCW rate order also required an $8.3 million decrease in natural gas rates, which included $7.1 million of recovery for the 2009 decoupling deferral. The new rates were effective January 14, 2011, and reflected a 10.30% return on common equity, down from a 10.90% return on common equity in the previous rate order, and a common equity ratio of 51.65% in WPS's regulatory capital structure.

The order also addressed the new Wisconsin electric fuel rule, which was finalized on March 1, 2011. The new fuel rule was effective retroactive to January 1, 2011. It requires the deferral of under or over-collections of fuel and purchased power costs that exceed a 2% price variance from the cost of fuel and purchased power included in rates. Under or over-collections deferred in the current year will be recovered or refunded in a future rate proceeding.

Michigan

2012 UPPCO Rates

On December 20, 2011, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $4.2 million, effective January 1, 2012. The new rates reflect a 10.20% return on common equity and a common equity ratio of 54.90% in UPPCO's regulatory capital structure. The settlement required UPPCO to terminate its existing decoupling mechanism, effective December 31, 2011. Additionally, the settlement agreement states that if UPPCO files a rate case in 2013, the earliest effective date for new final rates or self-implemented rates is January 1, 2014. In April 2012, the State of Michigan Court of Appeals ruled in a Detroit Edison proceeding that the MPSC did not have authority to approve electric decoupling mechanisms. As a result of this ruling, UPPCO expensed $1.5 million in the first quarter of 2012 related to electric decoupling amounts previously deferred for regulatory recovery. It is unknown at this time whether the ruling will be appealed.

2011 UPPCO Rates

On December 21, 2010, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $8.9 million, effective January 1, 2011. The new rates reflected a 10.30% return on common equity and a common equity ratio of 54.86% in UPPCO's regulatory capital structure. The order required UPPCO to terminate its uncollectibles expense tracking mechanism after the close of December 2010 business, but retained the decoupling mechanism.

Illinois

2012 Rates

On January 10, 2012, the ICC issued a final order authorizing a retail natural gas rate increase of $57.8 million for PGL and $1.9 million for NSG, effective January 21, 2012. The rates for PGL reflect a 9.45% return on common equity and a common equity ratio of 49.00% in PGL's regulatory capital structure. The rates for NSG reflect a 9.45% return on common equity and a common equity ratio of 50.00% in NSG's regulatory capital structure. The rate order also approved a permanent decoupling mechanism. On February 23, 2012, the ICC rejected the rehearing requests filed by PGL, NSG, and certain interveners. Two interveners, including the Illinois Attorney General, filed appeals of the rate order, including the permanent decoupling mechanism.

The Illinois Attorney General filed a motion with the ICC to stay the implementation of the permanent decoupling mechanism or, in the alternative, make collections subject to refund. The ICC denied the motion. However, the ICC issued an amendatory order with unclear language directing PGL and NSG to identify funds, which would be due to them or customers absent a permanent decoupling mechanism, for potential distribution depending on the results of a final appellate court order. PGL, NSG, and the Illinois Attorney General each requested clarification from the ICC regarding this language, but the ICC has not yet ruled and has no deadline or obligation to do so. Under current Illinois precedent, a utility generally cannot be required to reverse amounts previously recovered or refunded prior to an appellate court decision overturning an ICC-approved rate. Generally, any reversal only applies to periods after an appellate court decision. Under the permanent decoupling mechanism, amounts deferred are subject to an annual reconciliation, with recoveries or refunds occurring in April through December of the following calendar year. We expect to recover or refund amounts deferred in 2012 beginning in April 2013. As of March 31, 2012, PGL recorded approximately $12 million and NSG recorded approximately $1 million under the permanent decoupling mechanism as regulatory assets pending future recovery. However, these amounts will change throughout the remainder of 2012 based on actual customer usage. At this time, management believes recovery is probable; however, depending on the nature and timing of any appellate court decision, the ability to ultimately recover or refund amounts under decoupling could be affected. In addition, an appeal of the pilot decoupling order, which was effective March 2008 through February 2012, is pending and, depending on the outcome, could impact the permanent decoupling mechanism.

Rider ICR

On January 21, 2010, the ICC approved a rider mechanism for PGL to earn a return on and recover the costs, above an annual baseline, of the AMRP through a special charge on customers' bills, known as Rider ICR. The AMRP is a 20-year project that began in 2011 under which PGL is replacing its cast iron and ductile iron pipes with steel and polyethylene pipes. In June 2010, the ICC issued a rehearing order approving PGL's proposed baseline of $45.28 million with an annual escalation factor. Recovery of costs for the AMRP became effective on April 1, 2011. On September 30, 2011, the Illinois Appellate Court, First District, reversed the ICC's approval of Rider ICR, concluding it was improper single issue ratemaking. PGL and the ICC filed for leave to appeal with the Illinois Supreme Court, but their requests were denied. In March 2012, the Illinois Appellate Court remanded the matter to the ICC for further proceeding consistent with its September 30, 2011 decision. As a result, it is possible that the ICC may require PGL to refund amounts previously collected from customers under Rider ICR related to deliveries on or after September 30, 2011.

2009 Illinois Legislation

In July 2009, Illinois Senate Bill (SB) 1918 was signed into law. Under SB 1918, PGL and NSG filed a bad debt rider with the ICC in September 2009 to recover or refund the incremental difference between the rate case authorized uncollectible expense and the actual uncollectible expense reported to the ICC each year. The ICC approved the rider in February 2010. SB 1918 also requires a percentage of income payment plan for low-income utility customers, which became a permanent program in the fourth quarter of 2011. Additionally, SB 1918 requires an energy efficiency program to meet specified energy efficiency standards, which the ICC approved in May 2011. The first program year began in June 2011. Finally, SB 1918 requires an on-bill financing program that PGL and NSG will operate with their energy efficiency program. The program began in October 2011 and allows certain residential customers to borrow funds from a third-party lender to invest in energy saving measures and to pay the funds back over time through a charge on their utility bill.

Minnesota

2011 Rates

On November 30, 2010, MERC filed an application with the MPUC to increase retail natural gas rates by $15.2 million. The filing includes a request for an 11.25% return on common equity and a common equity ratio of 50.20% in MERC's regulatory capital structure. On January 28, 2011, the MPUC approved an interim rate order authorizing MERC a retail natural gas rate increase of $7.5 million, effective February 1, 2011. The interim rates reflect a 10.21% return on common equity and a common equity ratio of 50.20% in MERC's regulatory capital structure. On April 2, 2012, the Administrative Law Judge filed a proposed order to increase retail natural gas rates by $10.7 million. The proposed order includes a 9.41% return on common equity and a common equity ratio of 50.48% in MERC's regulatory capital structure. The interim rate increase is subject to refund pending the final rate order, which is expected in the second half of 2012.

Federal

Through a series of orders issued by the FERC, Regional Through and Out Rates for transmission service between the MISO and the PJM Interconnection were eliminated effective December 1, 2004. To compensate transmission owners for the revenue they would no longer receive due to this rate elimination, the FERC ordered a transitional pricing mechanism called the Seams Elimination Charge Adjustment (SECA) be put into place. Load-serving entities paid these SECA charges during a 16-month transition period from December 1, 2004, through March 31, 2006.

Integrys Energy Services initially expensed the majority of the total $19.2 million of billings received for the 16-month transitional period. The remaining amount was considered probable of recovery due to inconsistencies between the FERC's SECA order and the transmission owners' compliance filings. Integrys Energy Services protested FERC's order, and in August 2006, the administrative law judge hearing the case issued an Initial Decision that was in substantial agreement with all of Integrys Energy Services' positions. In May 2010, the FERC ruled favorably for Integrys Energy Services on two issues, but reversed the rulings of the Initial Decision on nearly every other substantive issue. Integrys Energy Services and numerous other parties filed for rehearing of the FERC's order. On September 30, 2011, the FERC denied rehearing of its order on the Initial Decision. The FERC has not yet issued an order on the compliance filings made by transmission owners.

As of March 31, 2012, Integrys Energy Services expected to receive future refunds of $3.8 million. Once the orders on compliance filings are issued, refunds will be made. Any refunds will include interest for the period from payment to refund.

NOTE 20—SEGMENTS OF BUSINESS

At March 31, 2012, we reported five segments, which are described below.

- The natural gas utility segment includes the regulated natural gas utility operations of WPS, PGL, NSG, MERC, and MGU.
- The electric utility segment includes the regulated electric utility operations of WPS and UPPCO.
- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company with operations in Wisconsin, Michigan, Minnesota, and Illinois.
- Integrys Energy Services is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas to commercial, industrial, and residential customers in deregulated markets. In addition, Integrys Energy Services invests in energy assets with renewable attributes.
- The holding company and other segment includes the operations of the Integrys Energy Group holding company and the PELLC holding company, along with any nonutility activities at WPS, UPPCO, PGL, NSG, MERC, MGU, and IBS. The operations of ITF were included in this segment beginning on September 1, 2011, when we acquired Trillium USA and Pinnacle CNG Systems.

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The tables below present information related to our reportable segments:

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Three Months Ended March 31, 2012								
External revenues	$ 664.0	$ 307.0	$ —	$ 971.0	$ 272.8	$ 7.5	$ —	$ 1,251.3

Intersegment revenues	**1.7**	**—**	**—**	**1.7**	**0.2**	**0.7**	**(2.6)**	**—**
Depreciation and amortization expense	**32.4**	**22.0**	**—**	**54.4**	**2.9**	**5.5**	**(0.1)**	**62.7**
Earnings in equity method investments	**—**	**—**	**20.8**	**20.8**	**0.1**	**0.2**	**—**	**21.1**
Miscellaneous income	**0.2**	**0.1**	**—**	**0.3**	**0.6**	**5.7**	**(4.2)**	**2.4**
Interest expense	**12.0**	**9.2**	**—**	**21.2**	**0.6**	**12.9**	**(4.2)**	**30.5**
Provision (benefit) for income taxes	**51.5**	**10.2**	**7.5**	**69.2**	**(12.9)**	**(9.5)**	**—**	**46.8**
Net income (loss) from continuing operations	**78.7**	**25.0**	**13.3**	**117.0**	**(20.1)**	**0.9**	**—**	**97.8**
Discontinued operations	**—**	**—**	**—**	**—**	**—**	**1.9**	**—**	**1.9**
Preferred stock dividends of subsidiary	**(0.1)**	**(0.7)**	**—**	**(0.8)**	**—**	**—**	**—**	**(0.8)**
Net income (loss) attributed to common shareholders	**78.6**	**24.3**	**13.3**	**116.2**	**(20.1)**	**2.8**	**—**	**98.9**

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	**Natural Gas Utility**	**Electric Utility**	**Electric Transmission Investment**	**Total Regulated Operations**	**Integrys Energy Services**	**Holding Company and Other**	**Reconciling Eliminations**	**Integrys Energy Group Consolidated**
Three Months Ended <u>March 31, 2011</u>								
External revenues	$ 851.3	$ 317.4	$ —	$ 1,168.7	$ 455.2	$ 3.2	$ —	$ 1,627.1
Intersegment revenues	2.1	5.2	—	7.3	0.3	0.4	(8.0)	—
Depreciation and amortization expense	31.2	22.1	—	53.3	3.3	5.8	(0.1)	62.3
Earnings in equity method investments	—	—	19.2	19.2	—	0.2	—	19.4
Miscellaneous income	0.1	0.3	—	0.4	0.9	6.0	(5.5)	1.8
Interest expense	12.4	12.0	—	24.4	0.5	15.4	(5.5)	34.8
Provision (benefit) for income taxes	52.2	11.8	7.8	71.8	5.6	(5.7)	—	71.7
Net income (loss) from continuing operations	77.4	25.7	11.4	114.5	10.7	(1.8)	—	123.4
Discontinued operations	—	—	—	—	0.1	—	—	0.1
Preferred stock dividends of subsidiary	(0.2)	(0.6)	—	(0.8)	—	—	—	(0.8)
Net income (loss) attributed to common shareholders	77.2	25.1	11.4	113.7	10.8	(1.8)	—	122.7

NOTE 21—NEW ACCOUNTING PRONOUNCEMENTS

<u>Recently Adopted Accounting Guidance</u>

We adopted ASU 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS)." The amendments change the wording used to describe the requirements for measuring fair value and also require new disclosures about fair value measurements. The amendments also clarify the intent concerning the application of existing fair value measurement requirements. Adoption of this new guidance resulted in new disclosures in Note 17, "*Fair Value*," but did not affect our fair value measurements.

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We adopted ASU 2011-05, "Presentation of Comprehensive Income," and ASU 2011-12, "Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05." The guidance requires that the total of comprehensive income, the components of net income, and the components of OCI be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. We elected to include a separate statement of comprehensive income.

ASU 2011-08, "Testing Goodwill for Impairment," was effective January 1, 2012. The amendments give companies an option to first perform a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If a company concludes that this is the case, the quantitative impairment test is required. Otherwise, a company can bypass the quantitative impairment test. Adoption of this guidance did not have an impact on our financial statements in the first quarter of 2012.

<u>Recently Issued Accounting Guidance Not Yet Effective</u>

ASU 2011-11, “Disclosures about Offsetting Assets and Liabilities,” was issued in December 2011. The guidance requires enhanced disclosures about offsetting and related arrangements. This guidance is effective for our reporting period ending March 31, 2013. Management is currently evaluating the impact that the adoption of this standard will have on our financial statements.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with the accompanying financial statements and related notes and our Annual Report on Form 10-K for the year ended December 31, 2011.

SUMMARY

We are a diversified energy holding company with regulated natural gas and electric utility operations (serving customers in Illinois, Michigan, Minnesota, and Wisconsin), an approximate 34% equity ownership interest in ATC (a federally regulated electric transmission company operating in Wisconsin, Michigan, Minnesota, and Illinois), and nonregulated energy operations.

RESULTS OF OPERATIONS

Earnings Summary

(Millions, except per share amounts)	Three Months Ended March 31 2012	2011	Change in 2012 Over 2011
Natural gas utility operations	**$ 78.6**	$ 77.2	1.8%
Electric utility operations	**24.3**	25.1	(3.2)%
Electric transmission investment	**13.3**	11.4	16.7%
Integrys Energy Services’ operations	**(20.1)**	10.8	N/A
Holding company and other operations	**2.8**	(1.8)	N/A
Net income attributed to common shareholders	**$ 98.9**	$ 122.7	(19.4)%
Basic earnings per share	**$ 1.26**	$ 1.57	(19.7)%
Diluted earnings per share	**$ 1.25**	$ 1.56	(19.9)%
Average shares of common stock			
Basic	**78.6**	78.3	0.4%
Diluted	**79.2**	78.6	0.8%

First Quarter 2012 Compared with First Quarter 2011

Our 2012 first quarter earnings were $98.9 million, compared with 2011 first quarter earnings of $122.7 million. The $23.8 million decrease in earnings was driven by:

- A $25.5 million after-tax non-cash decrease in Integrys Energy Services’ margins related to derivative and inventory fair value adjustments.
- A $5.5 million after-tax decrease in Integrys Energy Services’ realized margins.
- A $3.2 million after-tax decrease in electric utility margins, driven by a decrease in wholesale margins due to lower sales volumes, as well as the write-off of UPPCO’s net regulatory asset related to decoupling.

These decreases were partially offset by:

- A $5.9 million increase from the remeasurement of unrecognized tax benefit liabilities.
- A $2.6 million after-tax decrease in interest expense, driven by lower average outstanding long-term debt in 2012.

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Regulated Natural Gas Utility Segment Operations

Change in

(Millions, except heating degree days)		Three Months Ended March 31 2012		2011	2012 Over 2011
Revenues	$	**665.7**	$	853.4	(22.0)%
Purchased natural gas costs		**346.5**		531.1	(34.8)%
Margins		**319.2**		322.3	(1.0)%
Operating and maintenance expense		**135.3**		139.8	(3.2)%
Depreciation and amortization expense		**32.4**		31.2	3.8%
Taxes other than income taxes		**9.5**		9.4	1.1%
Operating income		**142.0**		141.9	0.1%
Miscellaneous income		**0.2**		0.1	100.0%
Interest expense		**(12.0)**		(12.4)	(3.2)%
Other expense		**(11.8)**		(12.3)	(4.1)%
Income before taxes	$	**130.2**	$	129.6	0.5%
Retail throughput in therms					
Residential		**606.4**		782.4	(22.5)%
Commercial and industrial		**183.4**		238.4	(23.1)%
Other		**18.7**		21.5	(13.0)%
Total retail throughput in therms		**808.5**		1,042.3	(22.4)%
Transport throughput in therms					
Residential		**87.1**		114.5	(23.9)%
Commercial and industrial		**476.7**		536.7	(11.2)%
Total transport throughput in therms		**563.8**		651.2	(13.4)%
Total throughput in therms		**1,372.3**		1,693.5	(19.0)%
Weather					
Average heating degree days		**2,589**		3,562	(27.3)%

First Quarter 2012 Compared with First Quarter 2011

Margins

Natural gas utility margins are defined as natural gas utility operating revenues less purchased natural gas costs. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas revenues since we pass through prudently incurred natural gas commodity costs to our customers in current rates. There was an approximate 16% decrease in the average per-unit cost of natural gas sold during the first quarter of 2012, which had no impact on margins.

Regulated natural gas utility segment margins decreased $3.1 million, driven by:

- An approximate $9 million net decrease in margins as a result of a 19.0% decrease in volumes sold.
  - Warmer weather during the first quarter of 2012, as shown by the 27.3% decrease in heating degree days, drove an approximate $53 million decrease in margins.
  - Higher sales volumes excluding the impact of weather resulted in an approximate $10 million increase in margins. This increase was due to a combination of both higher use per customer and higher average customer counts, which we primarily attribute to improved economic conditions for certain customers.

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  - The net margin decrease due to sales volumes was partially offset by an approximate $34 million quarter-over-quarter increase in decoupling recovery at certain natural gas utilities. Although decoupling was implemented to minimize the impact of changes in sales volumes, it does not cover all jurisdictions or customers. During 2012, decoupling lessened the negative impact from some of the decreased sales volumes through higher future recoveries from customers. During 2011, decoupling lessened the positive impact from some of the increased sales volumes through higher future refunds to customers.

- An approximate $3 million decrease in margins related to certain riders at PGL and NSG. Higher regulatory refunds and lower regulatory recoveries under these riders are offset by equal decreases in operating and maintenance expense, resulting in no impact on earnings.

- We recovered approximately $4 million less for environmental cleanup costs at our former manufactured gas plant sites in 2012. The lower recovery reflects a pass-through to our customers in rates of an environmental settlement received from a potentially responsible party's performance and payment bond. See Note 11, "*Commitment and Contingencies*," for more information about the manufactured gas plant sites.

- We refunded approximately $1 million more to customers under bad debt riders in 2012. See Note 19, "*Regulatory Environment*," for more information.

- We billed approximately $2 million more to customers for energy efficiency programs in 2012. See Note 19, "*Regulatory Environment*," for more information.

The decrease in margins was partially offset by:

- An approximate $10 million net increase in margins from rate orders. See Note 19, "*Regulatory Environment*," for more information on these rate orders.

  - The rate increase at PGL, effective January 21, 2012, and other impacts of rate design, had an approximate $14 million positive impact on margins.

  - A reduction in rates at WPS, effective January 1, 2012, resulted in an approximate $3 million negative impact on margins. The rate decrease was driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The margin impact from the reduction in contributions is offset by lower operating expenses, resulting in no impact on earnings.

Operating Income

Operating income at the regulated natural gas utility segment increased $0.1 million. This increase was primarily driven by a $4.5 million decrease in operating and maintenance expenses, partially offset by the $3.1 million decrease in margins discussed above and a $1.2 million increase in depreciation and amortization expense.

The decrease in operating and maintenance expenses primarily related to:

- A $3.5 million decrease in employee benefit expenses, primarily driven by lower postretirement and employee health care costs. Lower postretirement expenses were driven by an increase in plan assets due to contributions to our trust. Lower employee health claims experience contributed to the decrease in employee health care costs.

- An approximate $3 million net decrease due to higher amortization of regulatory liabilities related to bad debt riders, lower amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites, and an increase in expense and regulatory liabilities related to energy efficiency programs, all at PGL and NSG. Margins decreased by an equal amount, resulting in no impact on earnings.

- A $2.9 million decrease in energy efficiency program expenses related to WPS's Focus on Energy Program and MERC's conservation improvement program. Costs for both programs are recovered in rates, resulting in no impact on earnings.

- A $1.8 million decrease in injuries and damages expense resulting from a large number of claims accrued in the first quarter of 2011.

- A $1.7 million decrease in bad debt expense, driven by a new cost of gas component included as part of PGL's and NSG's bad debt expense tracking mechanisms. The change in the bad debt mechanisms was approved in PGL's and NSG's most recent rate orders, effective January 21, 2012. As a result of this component, bad debt expense was partially impacted by lower natural gas costs in 2012 and the decrease in volumes related to warmer weather discussed above.

- These decreases were partially offset by a $7.4 million increase in natural gas distribution costs. Costs associated with permits, restoration, transportation, and other miscellaneous distribution costs contributed to the increase.

Regulated Electric Utility Segment Operations

(Millions, except degree days)	Three Months Ended March 31 2012	2011	Change in 2012 Over 2011
Revenues	$ **307.0**	$ 322.6	(4.8)%
Fuel and purchased power costs	**127.5**	137.8	(7.5)%
Margins	**179.5**	184.8	(2.9)%
Operating and maintenance expense	**100.3**	101.2	(0.9)%

Depreciation and amortization expense	**22.0**	22.1	(0.5)%
Taxes other than income taxes	**12.9**	12.3	4.9%
Operating income	**44.3**	49.2	(10.0)%
Miscellaneous income	**0.1**	0.3	(66.7)%
Interest expense	**(9.2)**	(12.0)	(23.3)%
Other expense	**(9.1)**	(11.7)	(22.2)%
Income before taxes	**$ 35.2**	$ 37.5	(6.1)%
Sales in kilowatt-hours			
Residential	**775.2**	814.3	(4.8)%
Commercial and industrial	**2,087.8**	2,053.2	1.7%
Wholesale	**1,023.5**	1,062.2	(3.6)%
Other	**10.9**	11.0	(0.9)%
Total sales in kilowatt-hours	**3,897.4**	3,940.7	(1.1)%
Weather			
WPS:			
Heating degree days	**2,864**	3,892	(26.4)%
Cooling degree days	**11**	—	N/A
UPPCO:			
Heating degree days	**3,282**	4,108	(20.1)%

First Quarter 2012 Compared with First Quarter 2011

Margins

Electric margins are defined as electric operating revenues less fuel and purchased power costs. Management believes that electric utility margins provide a more meaningful basis for evaluating electric utility operations than electric operating revenues. To the extent changes in fuel and purchased power costs are passed through to customers, the changes are offset by comparable changes in operating revenues.

Regulated electric utility segment margins decreased $5.3 million, driven by:

- An approximate $3 million decrease in margins due to impacts from the WPS 2012 rate case re-opener. The PSCW approved a rate increase effective January 1, 2012. The rate increase was driven by anticipated increases in fuel and purchased power costs that did not materialize. Under the fuel rules, WPS deferred a portion of the difference between the costs included in rates and the actual fuel costs. This portion will be refunded to customers. Excluding the impact from fuel and purchased power costs, the 2012 rate case re-opener resulted in a rate decrease. The rate decrease was driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The margin impact from the reduction in contributions to the Focus on Energy Program was offset by lower operating expenses due to reduced payments to the program in 2012.

- An approximate $2 million decrease in wholesale margins, driven by a decrease in sales volumes. The decrease was primarily due to the loss of wholesale customers and a reduction in sales to one large customer.

- A $1.5 million decrease in margins due to the write-off of UPPCO's net regulatory asset related to its 2010 and 2011 decoupling deferrals. The write-off was the result of the Michigan Court of Appeals ruling in a Detroit Edison case which held that the MPSC did not have the authority to approve electric decoupling mechanisms.

- These decreases were partially offset by:

  - An approximate $1 million increase in margins due to a retail electric rate increase at UPPCO, effective January 1, 2012.

  - An approximate $1 million increase in margins from large commercial and industrial customers due to a 4.1% increase in sales volumes. We primarily attribute this increase to improved economic conditions.

Operating Income

Operating income at the regulated electric utility segment decreased $4.9 million. The decrease was driven by the $5.3 million decrease in margins, partially offset by a $0.4 million decrease in operating expenses. The decrease in operating expenses was driven by:

- A $2.8 million decrease in customer assistance expense related to payments made to the Focus on Energy Program. These payments are recovered in rates, resulting in no impact on earnings.

- This decrease was partially offset by:
  - A $1.5 million increase in employee benefit expenses.
  - A $0.6 million increase in taxes other than income taxes, driven by increases in property taxes and payroll taxes.

Other Expense

Other expense decreased $2.6 million, driven by a decrease in interest expense due to the maturity and repayment of $150 million of long-term debt at WPS in August 2011.

Electric Transmission Investment Segment Operations

First Quarter 2012 Compared with First Quarter 2011

Miscellaneous Income

Miscellaneous income at the electric transmission investment segment increased $1.6 million. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. We earn higher returns each year as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

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Integrys Energy Services Nonregulated Segment Operations

(Millions, except natural gas sales volumes)	Three Months Ended March 31 2012	2011	Change in 2012 over 2011
Revenues	**$ 273.0**	$ 455.5	(40.1)%
Cost of sales	**271.7**	402.5	(32.5)%
Margins	**1.3**	53.0	(97.5)%
Margin Detail			
Realized retail electric margins	**16.9**	20.3	(16.7)%
Realized wholesale electric margins **(1)**	**(0.5)**	(0.3)	66.7%
Realized energy asset margins	**5.1**	7.3	(30.1)%
Fair value accounting adjustments	**(43.5)**	10.0	N/A
Electric and other margins	**(22.0)**	37.3	N/A
Realized retail natural gas margins	**23.5**	23.5	—
Realized wholesale natural gas margins **(1)**	**(0.6)**	2.8	N/A
Lower-of-cost-or-market inventory adjustments	**1.6**	0.1	1,500.0%
Fair value accounting adjustments	**(1.2)**	(10.7)	(88.8)%
Natural gas margins	**23.3**	15.7	48.4%
Operating and maintenance expense	**29.2**	32.0	(8.8)%
Depreciation and amortization	**2.9**	3.3	(12.1)%
Taxes other than income taxes	**2.3**	1.8	27.8%
Operating (loss) income	**(33.1)**	15.9	N/A
Miscellaneous income	**0.7**	0.9	(22.2)%
Interest expense	**(0.6)**	(0.5)	20.0%
Other income	**0.1**	0.4	(75.0)%
(Loss) income before taxes	**$ (33.0)**	$ 16.3	N/A
Physically settled volumes			
Retail electric sales volumes in kwh	**2,918.9**	2,952.5	(1.1)%
Wholesale assets and distributed solar electric sales volumes in kwh **(2)**	**88.9**	72.6	22.5%
Retail natural gas sales volumes in bcf	**43.8**	48.5	(9.7)%

kwh — kilowatt-hours

bcf — billion cubic feet

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(1) Realized wholesale activity relates to remaining contracts for which offsetting positions were entered into.

(2) The volumes related to the remaining wholesale electric contracts are not significant.

First Quarter 2012 Compared with First Quarter 2011

Revenues

Revenues decreased $182.5 million, driven by lower quarter-over-quarter average commodity prices.

Margins

Integrys Energy Services' margins decreased $51.7 million. The significant items contributing to the change in margins were as follows:

Electric and Other Margins

Realized retail electric margins

Realized retail electric margins decreased $3.4 million. The decrease was driven by the expiration at the end of 2011 of several large, lower-margin customer contracts in the Illinois market.

Realized energy asset margins

Realized energy asset margins decreased $2.2 million. The decrease was primarily due to the expiration of a long-term capacity contract in the fourth quarter of 2011.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services' margins. Fair value adjustments caused a $53.5 million decrease in electric margins quarter over quarter. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Inventory accounting adjustments

Integrys Energy Services' physical natural gas inventory is valued at the lower of cost or market. When the market price of natural gas is lower than the carrying value of the inventory, write-downs are recorded within margins to reflect inventory at the end of the period at its net realizable value. These write-downs result in higher margins in future periods as the inventory that was written down is sold. The $1.5 million quarter-over-quarter increase in margins from inventory adjustments was driven by a higher volume of inventory withdrawn from storage for which write-downs had previously been recorded.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services' margins. Fair value adjustments caused a $9.5 million increase in natural gas margins quarter over quarter. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating (Loss) Income

Integrys Energy Services' operating income decreased $49.0 million. The main driver of the decrease was the $51.7 million decrease in margins discussed above, partially offset by a $2.8 million decrease in operating and maintenance expenses driven by a $2.9 million decrease in employee benefit expenses.

Holding Company and Other Segment Operations

(Millions)	Three Months Ended March 31 2012	2011	Change in 2012 over 2011
Operating income (loss)	**$ (1.6)**	$ 1.7	N/A
Other expense	**(7.0)**	(9.2)	(23.9)%

Net loss before taxes	**$ (8.6)**	$ (7.5)	14.7%

First Quarter 2012 Compared with First Quarter 2011

Operating Income (Loss)

Operating income at the holding company and other segment decreased $3.3 million in 2012. The decrease was driven partially by operating losses of $1.7 million at ITF, a subsidiary formed in September 2011 to hold our compressed natural gas businesses. Lower intercompany fees of $1.4 million charged by the holding company to Integrys Energy Services, related to lower interest charges and decreased use of an intercompany credit agreement, also contributed to the decrease in operating income.

Other Expense

Other expense at the holding company and other segment decreased $2.2 million in 2012. Interest expense on long-term debt decreased, driven by lower average outstanding long-term debt in 2012.

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Provision for Income Taxes

	Three Months Ended March 31	
	2012	**2011**
Effective Tax Rate	**32.4%**	36.8%

First Quarter 2012 Compared with First Quarter 2011

Our effective tax rate decreased in the first quarter of 2012. This decrease primarily related to a remeasurement of our unrecognized tax benefit liability that better reflects how the underlying uncertain tax positions are resolving themselves in various taxing jurisdictions.

Discontinued Operations

First Quarter 2012 Compared with First Quarter 2011

Income from discontinued operations, net of tax, increased $1.8 million in 2012. During the first quarter of 2012, we recorded an after-tax gain in discontinued operations at the holding company and other segment when we remeasured an unrecognized tax benefit liability that better reflects how the underlying uncertain tax positions are resolving themselves in various taxing jurisdictions.

LIQUIDITY AND CAPITAL RESOURCES

We believe we have adequate resources to fund ongoing operations and future capital expenditures. These resources include our cash balances, liquid assets, operating cash flows, access to equity and debt capital markets, and available borrowing capacity under existing credit facilities. Our borrowing costs can be impacted by short-term and long-term debt ratings assigned by independent credit rating agencies, as well as the market rates for interest. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside of our control.

Operating Cash Flows

During the quarter ended March 31, 2012, net cash provided by operating activities was $225.8 million, compared with $395.5 million for the same quarter in 2011. The $169.7 million decrease in net cash provided by operating activities was largely driven by:

- A $140.2 million increase in contributions to pension and other postretirement benefit plans.
- A decrease in net income, adjusted for non-cash items.
- Partially offsetting these decreases was a quarter-over-quarter net increase in cash provided by working capital of $6.3 million. This increase was primarily due to the following:
  - A $49.9 million decrease in accounts receivable and accrued unbilled revenues in 2012, compared to a $50.1 million increase in 2011. The change was driven by the warmer quarter-over-quarter weather and the decline in natural gas prices that occurred in the first quarter of 2012.
  - A positive impact from an $18.7 million increase in other current liabilities in 2012, compared with a $26.0 million decrease in other current liabilities in 2011. This change was driven by increases in 2012 in PGL's and NSG's liabilities related to natural gas costs refundable through rate adjustments versus decreases in these liabilities in 2011.
  - A $26.2 million positive impact from a quarter-over-quarter decrease in other current assets. The change was driven by higher tax refunds accrued in 2011, compared with 2012, primarily due to 100% bonus depreciation and increased tax deductions for pension funding in 2011.

In addition, we received federal and state income tax refunds in the first quarter of 2012.

- These increases in cash provided by working capital were partially offset by a $53.6 million quarter-over-quarter increase in cash used for accounts payable, a $20.0 million quarter-over-quarter decrease in cash generated from inventory, and an $82.5 million quarter-over-quarter decrease in the temporary LIFO liquidation credit, all of which were driven by the warmer weather and the decline in natural gas prices that occurred in the first quarter of 2012.

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Investing Cash Flows

Net cash used for investing activities was $136.7 million during the quarter ended March 31, 2012, compared with $56.2 million for the same quarter in 2011. The $80.5 million increase in net cash used for investing activities was primarily due to a $71.8 million increase in cash used to fund capital expenditures (discussed below).

Capital Expenditures

Capital expenditures by business segment for the three months ended March 31 were as follows:

Reportable Segment (millions)	2012	2011	Change
Electric utility	**$ 30.8**	$ 20.7	$ 10.1
Natural gas utility	**78.9**	26.6	52.3
Integrys Energy Services	**8.2**	1.2	7.0
Holding company and other	**5.1**	2.7	2.4
Integrys Energy Group consolidated	**$ 123.0**	$ 51.2	$ 71.8

The increase in capital expenditures at the natural gas utility segment for the quarter ended March 31, 2012, compared with March 31, 2011, was primarily a result of the AMRP at PGL. The increase in capital expenditures at the electric utility segment was driven by various projects at the Columbia plant in 2012, partially offset by the purchase of a previous joint owner's interest in a combustion turbine in 2011.

Financing Cash Flows

Net cash used for financing activities was $74.9 million during the quarter ended March 31, 2012, compared with $323.0 million for the same quarter in 2011. The $248.1 million decrease in net cash used for financing activities was driven by:

- The repayment of $325.0 million of long-term debt in 2011.

- Partially offsetting this decrease in net cash used was a $55.7 million decrease in cash received from net short-term borrowings.

Significant Financing Activities

For information on short-term debt, see Note 8, "*Short-Term Debt and Lines of Credit.*"

For information on the issuance and redemption of long-term debt in 2012, see Note 9, "*Long-Term Debt.*"

From February 11, 2010 through April 30, 2011, we issued new shares of common stock to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. Beginning May 1, 2011, shares were purchased on the open market to meet the requirements of these plans.

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Credit Ratings

Our current credit ratings and the credit ratings for WPS, PGL, and NSG are listed in the table below:

Credit Ratings	Standard & Poor's	Moody's
Integrys Energy Group		
Issuer credit rating	A-	N/A
Senior unsecured debt	BBB+	Baa1
Commercial paper	A-2	P-2
Credit facility	N/A	Baa1
Junior subordinated notes	BBB	Baa2
WPS		

Issuer credit rating	A-	A2
First mortgage bonds	N/A	Aa3
Senior secured debt	A	Aa3
Preferred stock	BBB	Baa1
Commercial paper	A-2	P-1
Credit facility	N/A	A2
PGL		
Issuer credit rating	A-	A3
Senior secured debt	A-	A1
Commercial paper	A-2	P-2
NSG		
Issuer credit rating	A-	A3
Senior secured debt	A	A1

Credit ratings are not recommendations to buy or sell securities. They are subject to change, and each rating should be evaluated independently of any other rating.

On January 24, 2012, Standard & Poor's raised the issuer credit ratings for us, PGL, and NSG to "A-" from "BBB+." In addition, they raised our senior unsecured debt rating to "BBB+" from "BBB" and raised our junior subordinated notes rating to "BBB" from "BBB-." The outlook for us, PGL, and NSG was revised to "stable" from "positive." According to Standard & Poor's, the revised ratings reflect their view that our business risk profile improved to "excellent" from "strong" and that we continue to have a significant financial risk profile. The revised business risk profile assessment reflects the successful implementation of our strategic initiative to reduce our exposure to the nonutility businesses and our effective management of regulatory risk. WPS's outlook remained "stable."

Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of March 31, 2012, including those of our subsidiaries.

		Payments Due By Period			
(Millions)	**Total Amounts Committed**	**2012**	**2013 to 2014**	**2015 to 2016**	**2017 and Thereafter**
Long-term debt principal and interest payments (1)	**$ 2,948.1**	**$ 330.8**	**$ 581.0**	**$ 633.9**	**$ 1,402.4**
Operating lease obligations	**80.5**	**6.3**	**14.0**	**8.3**	**51.9**
Commodity purchase obligations (2)	**2,461.2**	**487.7**	**726.3**	**338.9**	**908.3**
Purchase orders (3)	**536.1**	**534.2**	**1.9**	**—**	**—**
Capital contributions to equity method investment	**5.1**	**5.1**	**—**	**—**	**—**
Pension and other postretirement funding obligations (4)	**574.1**	**42.9**	**201.2**	**60.0**	**270.0**
Total contractual cash obligations	**$ 6,605.1**	**$ 1,407.0**	**$ 1,524.4**	**$ 1,041.1**	**$ 2,632.6**

(1) Represents bonds and notes issued, as well as loans made to us and our subsidiaries. We record all principal obligations on the balance sheet. For purposes of this table, it is assumed that the current interest rates on variable rate debt will remain in effect until the debt matures.

(2) Energy and related commodity supply contracts at Integrys Energy Services included as part of commodity purchase obligations are generally entered into to meet obligations to deliver energy and related products to customers; therefore, these costs will be recovered as customer sales contracts settle. The utility subsidiaries expect to recover the costs of their contracts in future customer rates.

(3) Includes obligations related to normal business operations and large construction obligations.

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2014.

The table above does not reflect payments related to the manufactured gas plant remediation liability of $608.1 million at March 31, 2012, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 11, "*Commitments and Contingencies*," for more information about environmental liabilities. The table also does not reflect any payments for the March 31, 2012, liability of $19.7 million related to unrecognized tax benefits, as the amount and timing of the payments are uncertain. See Note 10, "*Income Taxes*," for more information on unrecognized tax benefits.

Capital Requirements

As of March 31, 2012, our subsidiaries' capital expenditures for the three-year period 2012 through 2014 were expected to be as follows:

(Millions)		
WPS		
Environmental projects	$	511
Electric and natural gas distribution projects		201
Electric and natural gas delivery and customer service projects		64
Other projects		176
UPPCO		
Repairs and safety measures at hydroelectric facilities		16
Other projects		32
MGU		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects		35
MERC		
Natural gas pipe distribution system and other projects		53
PGL		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects		876
NSG		
Natural gas pipe distribution system and other projects		85
Integrys Energy Services		
Solar and other projects		99
IBS		
Corporate or shared services software and infrastructure projects		96
ITF		
Compressed natural gas fueling stations		71
Total capital expenditures	$	2,315

We expect to provide capital contributions to INDU Solar Holdings, LLC, (not included in the above table) of approximately $45 million in 2012.

We expect to provide capital contributions to ATC (not included in the above table) of approximately $19 million from 2012 through 2014.

All projected capital and investment expenditures are subject to periodic review and may vary significantly from the estimates, depending on a number of factors. These factors include, but are not limited to, industry restructuring, environmental requirements, regulatory constraints and requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, and economic trends.

Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management policies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage the liquidity and capital resource needs of the business segments. We plan to meet our capital requirements for the period 2012 through 2014 primarily through internally generated funds (net of forecasted dividend payments) and debt and equity financings. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth. We believe we have adequate financial flexibility and resources to meet our future needs.

At March 31, 2012, we and each of our subsidiaries were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 8, "Short-Term Debt and Lines of Credit," for more information on credit facilities and other short-term credit agreements. See Note 9, "Long-Term Debt," for more information on long-term debt.

Other Future Considerations

Decoupling

In certain jurisdictions, decoupling mechanisms have been implemented. These mechanisms differ state by state and allow utilities to adjust future rates to recover or refund all or a portion of the differences between actual and authorized margin.

- Decoupling for residential and small commercial and industrial sales was approved by the ICC on a four-year trial basis for PGL and NSG, effective March 1, 2008. In the PGL and NSG rate order approved on January 10, 2012, the ICC made the decoupling mechanism (based on total margin, excluding fixed charges) permanent for both companies. Interveners, including the Illinois Attorney General, oppose decoupling and have appealed the ICC's approval of both the pilot program and the permanent decoupling mechanism. PGL and NSG actively support the ICC's decision to approve decoupling. The Illinois Attorney General filed a motion with the ICC to stay the implementation of the permanent decoupling mechanism or, in the alternative, make collections subject to refund. The ICC denied the motion. However, the ICC issued an amendatory order with unclear language directing PGL and NSG to identify funds, which would be due to them or customers absent a permanent decoupling mechanism, for potential distribution depending on the results of a final appellate court order. PGL, NSG, and the Illinois Attorney General each requested clarification from the ICC regarding this language, but the ICC has not yet ruled and has no deadline or obligation to do so. Under current Illinois precedent, a utility generally cannot be required to reverse amounts previously recovered or refunded prior to an appellate court decision overturning an ICC-approved rate. Generally, any reversal only applies to periods after an appellate court decision. Under the permanent decoupling mechanism, amounts deferred are subject to an annual reconciliation, with recoveries or refunds occurring in April through December of the following calendar year. We expect to recover or refund amounts deferred in 2012 beginning in April 2013. As of March 31, 2012, PGL recorded approximately $12 million and NSG recorded approximately $1 million under the permanent decoupling mechanism as regulatory assets pending future recovery. However, these amounts will change throughout the remainder of 2012 based on actual customer usage. At this time, management believes recovery is probable; however, depending on the nature and timing of any appellate court decision, the ability to ultimately recover or refund amounts under decoupling could be affected. In addition, an appeal of the pilot decoupling order is pending and, depending on the outcome, could impact the permanent decoupling mechanism.

- Decoupling for natural gas and electric residential and small commercial and industrial sales was approved by the PSCW on a four-year trial basis for WPS, effective January 1, 2009, and ending on December 31, 2012. The mechanism does not adjust for variations in volumes resulting from changes in customer count compared to rate case levels, nor does it cover all customer classes. This decoupling mechanism includes an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. Amounts recoverable from or refundable to customers are subject to these caps and are included in rates upon approval in a rate order. Decoupling for 2012 and beyond is currently being addressed in WPS's 2013 rate case filing.

- Decoupling for UPPCO was approved for the majority of customer classes by the MPSC, effective January 1, 2010, and ended on December 31, 2011. However, in April 2012, the State of Michigan Court of Appeals ruled in a Detroit Edison proceeding that the MPSC did not have authority to approve electric decoupling mechanisms. As a result of this ruling, we expensed $1.5 million in the first quarter of 2012 related to electric decoupling amounts previously deferred for regulatory recovery at UPPCO. It is unknown at this time whether the ruling will be appealed. The MPSC opened a docket seeking comments regarding (1) the impact of the Court of Appeals decision on each of the affected utilities and their customers, and (2) opinions concerning the future, if any, of the use of electric decoupling mechanisms in Michigan.

- The MPSC granted an order, effective January 1, 2010, approving a decoupling mechanism for MGU that covers residential and small commercial and industrial customers. The decoupling mechanism does not adjust for weather-related usage, nor does it adjust for variations in volumes resulting from changes in customer count compared to rate case levels. The decoupling mechanism does not cover all customer classes. The Court of Appeals ruling discussed above did not affect MGU's decoupling mechanism because it did not apply to natural gas.

- In Minnesota, MERC proposed a decoupling mechanism in its November 30, 2010 general rate case filing, which was recommended in the Administrative Law Judge's proposed order on April 2, 2012. A final order is expected in the second half of 2012.

See Note 19, "*Regulatory Environment*," for more information.

Climate Change

The EPA began regulating greenhouse gas emissions under the Clean Air Act in January 2011 by applying the Best Available Control Technology (BACT) requirements (associated with the New Source Review program) to new and modified larger greenhouse gas emitters. Technology to remove and sequester greenhouse gas emissions is not commercially available at scale. Therefore, the EPA issued guidance that defines BACT in terms of improvements in energy efficiency as opposed to relying on pollution control equipment. In December 2010, the EPA announced its intent to develop new source performance standards for greenhouse gas emissions. The standards would apply to new and modified, as well as existing, electric utility steam generating units. On March 27, 2012, the EPA issued a proposed rule that would impose a carbon dioxide emission rate limit on new electric generating units. The proposed limit may prevent the construction of new coal units until technology becomes commercially available. The EPA planned to propose performance standards for existing units in 2011 and finalize them in 2012; however, that proposal has been delayed.

A risk exists that any greenhouse gas legislation or regulation will increase the cost of producing energy using fossil fuels. However, we believe the capital expenditures being made at our plants are appropriate under any reasonable mandatory greenhouse gas program. We also believe that future expenditures by our regulated electric and natural gas utilities that may be required to control greenhouse gas emissions or meet renewable portfolio standards will be recoverable in rates. We will continue to monitor and manage potential risks and opportunities associated with future greenhouse gas legislative or regulatory actions.

The majority of our generation and distribution facilities are located in the upper Midwest region of the United States. The same is true for the majority of our customers' facilities. The physical risks posed by climate change for these areas are not expected to be significant at this time. Ongoing evaluations will be conducted as more information on the extent of such physical changes becomes available.

Federal Health Care Reform

In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (HCR) were signed into law. HCR contains various provisions that will affect the cost of providing health care coverage to our active and retired employees and their dependents. Although these provisions become effective at various times over the next 10 years, some provisions that affect the cost of providing benefits to retirees were reflected in our financial statements in 2010 and 2011.

Beginning in 2013, a provision of HCR will eliminate the tax deduction for employer-paid postretirement prescription drug charges to the extent those charges will be offset by the receipt of a federal Medicare Part D subsidy. As a result, we eliminated $11.8 million of our deferred tax asset related to postretirement benefits in 2010. Of this amount, $10.8 million flowed through to net income as a component of income tax expense in 2010. The remaining $1.0 million was deferred for regulatory recovery at UPPCO. An additional $1.5 million was expensed in June 2011 for deferred income taxes related to a Wisconsin tax law change. In the fourth quarter of 2011, PGL and NSG recorded a regulatory asset of $5.8 million, reversing amounts previously expensed in 2010, as PGL and NSG were authorized recovery of these amounts in the rate order approved on January 10, 2012. In addition, WPS was authorized recovery in February 2012 for the portion related to its Michigan operations that was previously expensed in 2010. We have sought rate recovery for the remaining $5.9 million of income tax expense that relates to this tax law change associated with our regulated operations. If recovery in rates becomes probable in Wisconsin, income tax expense will be reduced in that period. We are not currently able to predict how much of the remaining portion, if any, will be recovered in rates.

Other provisions of HCR include the elimination of certain annual and lifetime maximum benefits and the broadening of plan eligibility requirements. It also includes the elimination of pre-existing condition restrictions, an excise tax on high-cost health plans, changes to the Medicare Part D prescription drug program, and numerous other changes. We successfully participated in the Early Retiree Reinsurance Program through the third quarter of 2011. Following the submission of our fourth quarter 2011 claim, we were informed that the program fund had been depleted and, as such, we are not anticipating any future funding.

Major provisions of HCR are currently being challenged and are under review by the United States Supreme Court. The Supreme Court is expected to rule on this matter in the second quarter of 2012. Until then, key provisions of HCR remain uncertain. We continue to assess the extent to which the provisions of the new law will affect our future health care and related employee benefit plan costs.

Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act)

The Dodd-Frank Act was signed into law in July 2010. However, significant rulings essential to its framework still remain outstanding. Depending on the final rules, certain provisions of the Dodd-Frank Act relating to derivatives could increase capital and/or collateral requirements. Since final rules for some of the most key elements relating to derivatives continue to be delayed, it is difficult to predict when the rules will be finalized at this time. We are monitoring developments related to this act and their potential impacts on our future financial results.

Federal Tax Law Changes

In December 2010, President Obama signed into law The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. This act includes tax incentives, such as an extension and increase of bonus depreciation, the extension of the research and experimentation credit, and the extension of treasury grants in lieu of claiming the investment tax credit or production tax credit for certain renewable energy investments. In September 2010, President Obama signed into law the Small Business Jobs Act of 2010. This act includes tax incentives that affect us, such as an extension to bonus depreciation and changes to listed property. We anticipate that these tax law changes will likely result in $140.0 million to $240.0 million of reduced cash payments for taxes during 2012. These tax incentives may also reduce utility rate base and, thus, future earnings relative to prior expectations. We have primarily used the proceeds from these incentives to make incremental contributions to our various employee benefit plans. In addition, these tax incentives have helped reduce our financing needs.

In December 2011, the National Defense Authorization Act (NDAA) was enacted. The most significant provision of the NDAA was to retroactively eliminate the application of the tax normalization rule for cash grants taken by a regulated utility in lieu of the investment tax credit or production tax credits. Prior to the enactment of NDAA, a regulated utility would have been required to amortize the grant in rates over the regulatory life of the renewable energy generating plant. Further, the allowed rate of return on the generating plant could not be reduced by the unamortized grant balance during the life of the plant. As a result of the enactment of NDAA, we are evaluating our options for taking advantage of cash grants in lieu of the production tax credits we are currently claiming for WPS's Crane Creek wind project.

CRITICAL ACCOUNTING POLICIES

We have reviewed our critical accounting policies for new critical accounting estimates and other significant changes and have found that the disclosures made in our Annual Report on Form 10-K for the year ended December 31, 2011, are still current and that there have been no significant changes.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We have potential market risk exposure related to commodity price risk, interest rate risk, and equity return and principal preservation risk. We are also exposed to other significant risks due to the nature of our subsidiaries' businesses and the environment in which we operate. We have risk management policies in place to monitor and assist in controlling these risks and may use derivative and other instruments to manage some of these exposures, as further described below.

Commodity Price Risk

To measure commodity price risk exposure, we employ a number of controls and processes, including a value-at-risk (VaR) analysis of certain of our exposures. Integrys Energy Services' VaR is calculated using non-discounted positions with a delta-normal approximation based on a one-day holding period and a 95% confidence level, as well as a ten-day holding period and 99% confidence level. For further explanation of our VaR calculation, see our 2011 Annual Report on Form 10-K.

The VaR for Integrys Energy Services' open commodity positions at a 95% confidence level with a one-day holding period is presented in the following table:

(Millions)	2012	2011
As of March 31	**$ 0.1**	$ 0.3
Average for 12 months ended March 31	**0.1**	0.3
High for 12 months ended March 31	**0.2**	0.3
Low for 12 months ended March 31	**0.1**	0.2

The VaR for Integrys Energy Services' open commodity positions at a 99% confidence level with a ten-day holding period is presented below:

(Millions)	2012	2011
As of March 31	**$ 0.4**	$ 1.2
Average for 12 months ended March 31	**0.5**	1.4
High for 12 months ended March 31	**0.7**	1.5
Low for 12 months ended March 31	**0.4**	1.1

The average, high, and low amounts were computed using the VaR amounts at each of the four quarter ends.

Interest Rate Risk

We are exposed to interest rate risk resulting from variable rate long-term debt and short-term borrowings. We manage exposure to interest rate risk by limiting the amount of variable rate obligations and continually monitoring the effects of market changes on interest rates. When it is advantageous to do so, we enter into long-term fixed rate debt. We may also enter into derivative financial instruments, such as swaps, to mitigate interest rate exposure.

Based on the variable rate debt outstanding at March 31, 2012, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $3.3 million. Comparatively, based on the variable rate debt outstanding at March 31, 2011, an increase in interest rates of 100 basis points would have increased annual interest expense by $1.5 million. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Other than the above-mentioned changes, our market risks have not changed materially from the market risks reported in our 2011 Annual Report on Form 10-K.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of Integrys Energy Group's disclosure controls and procedures (as defined by Securities Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based upon that evaluation, management, including our Chief Executive Officer and Chief Financial Officer, has concluded that Integrys Energy Group's disclosure controls and procedures were effective as of the end of the period covered by this report.

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined by Securities Exchange Act Rules 13a-15(f) and 15d-15(f)) during the quarter ended March 31, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For information on material legal proceedings and matters, see Note 11, "*Commitments and Contingencies*."

Item 1A. Risk Factors

There were no material changes in the risk factors previously disclosed in Part I, Item 1A of our 2011 Annual Report on Form 10-K, which was filed with the SEC on February 29, 2012.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Dividend Restrictions

We are a holding company and our ability to pay dividends is largely dependent upon the ability of our subsidiaries to make payments to us in the form of dividends or otherwise. For information regarding restrictions on the ability of our subsidiaries to pay us dividends, see Note 15, "*Common Equity*."

Issuer Purchases of Equity Securities

The following table provides a summary of common stock purchases for the three months ended March 31, 2012:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
01/01/12 - 01/31/12 (1) (2)	**16,848**	**$ 52.97**	**—**	**—**
02/01/12 - 02/29/12 (1) (2) (3)	**246,834**	**54.10**	**—**	**—**
03/01/12 - 03/31/12 (1) (2) (3)	**256,039**	**53.22**	**—**	**—**
Total	**519,721**	**$ 53.63**	**—**	**—**

(1) Represents shares purchased in the open market by American Stock Transfer & Trust Company to satisfy obligations under various equity compensation plans.

(2) Represents shares purchased in the open market by American Stock Transfer & Trust Company to provide shares to participants in the Stock Investment Plan.

(3) Represents shares purchased in the open market by American Stock Transfer & Trust Company and held in a rabbi trust under our Deferred Compensation Plan.

Item 6. Exhibits

The documents listed in the Exhibit Index are attached as exhibits or incorporated by reference herein.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant, Integrys Energy Group, Inc., has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Integrys Energy Group, Inc.

Date: May 2, 2012

/s/ Diane L. Ford
Diane L. Ford
Vice President and Corporate Controller

(Duly Authorized Officer and Chief Accounting Officer)

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INTEGRYS ENERGY GROUP
EXHIBIT INDEX TO FORM 10-Q
FOR THE QUARTER ENDED MARCH 31, 2012

Exhibit No.	Description
12	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Energy Group, Inc.
101 *	Financial statements from the Quarterly Report on Form 10-Q of Integrys Energy Group, Inc. for the quarter ended March 31, 2012, filed on May 2, 2012, formatted in eXtensible Business Reporting Language (XBRL): (i) the Condensed Consolidated Statements of Income, (ii) the Condensed Consolidated Statements of Comprehensive Income, (iii) the Condensed Consolidated Balance Sheets, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Notes To Financial Statements, and (vi) document and entity information.

* In accordance with Rule 406T of Regulation S-T, the information in these exhibits shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, except as expressly set forth by specific reference in such filing.

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Section 2: EX-12 (EX-12)

Exhibit 12

INTEGRYS ENERGY GROUP, INC.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Millions, except ratio)	Three Months Ended March 31 2012	For the Years Ended December 31 2011	2010	2009	2008	2007
EARNINGS						
Net income (loss) from continuing operations	**$ 97.8**	$ 230.9	$ 223.5	$ (70.3)	$ 114.8	$ 181.0
Provision for income taxes	**46.8**	133.9	148.2	83.7	61.1	86.0
Income from continuing operations before income taxes	**144.6**	364.8	371.7	13.4	175.9	267.0
Less:						
Undistributed earnings of less than 50% owned affiliates	**(4.1)**	(15.8)	(14.8)	(16.2)	(16.4)	3.8
Preferred stock dividends of subsidiary (a)	**(1.2)**	(5.1)	(5.3)	0.7	(4.8)	(5.2)
Interest capitalized (b)	**—**	—	—	(0.2)	—	—
Adjusted income (loss) from continuing operations before income taxes	**139.3**	343.9	351.6	(2.3)	154.7	265.6
Total fixed charges as defined	**32.7**	138.3	158.8	172.3	170.5	174.6
Total earnings as defined	**$ 172.0**	$ 482.2	$ 510.4	$ 170.0	$ 325.2	$ 440.2

FIXED CHARGES						
Interest expense	$ **30.5**	$ 128.8	$ 147.9	$ 164.8	$ 158.1	$ 164.5
Interest capitalized (c)	**0.1**	0.3	0.6	2.6	2.0	0.3
Interest factor applicable to rentals	**0.9**	4.1	5.0	5.6	5.6	4.6
Preferred stock dividends of subsidiary (a)	**1.2**	5.1	5.3	(0.7)	4.8	5.2
Total fixed charges as defined	$ **32.7**	$ 138.3	$ 158.8	$ 172.3	$ 170.5	$ 174.6
RATIO OF EARNINGS TO FIXED CHARGES	**5.3**	3.5	3.2	(d)	1.9	2.5

(a) Preferred stock dividends of subsidiary are computed by dividing the preferred stock dividends of subsidiary by 100% minus the income tax rate.

(b) Includes interest capitalized for the nonregulated segments.

(c) Includes allowance for funds used during construction.

(d) For 2009, earnings were inadequate to cover fixed charges by $2.3 million, driven by a pre-tax noncash goodwill impairment loss of $291.1 million.

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Section 3: EX-31.1 (EX-31.1)

Exhibit 31.1

Certification of Chief Executive Officer
Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a)
or 15d-14(a) under the Securities Exchange Act of 1934

I, Charles A. Schrock, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Integrys Energy Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 2, 2012

/s/ Charles A. Schrock
Charles A. Schrock
Chairman, President and Chief Executive Officer

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Section 4: EX-31.2 (EX-31.2)

Exhibit 31.2

Certification of Chief Financial Officer
Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a)
or 15d-14(a) under the Securities Exchange Act of 1934

I, Joseph P. O'Leary, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Integrys Energy Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 2, 2012

/s/ Joseph P. O'Leary
Joseph P. O'Leary
Senior Vice President and Chief Financial Officer

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Section 5: EX-32 (EX-32)

Exhibit 32

Written Statement of the Chief Executive Officer and Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350

Solely for the purposes of complying with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, we, the undersigned Chief Executive Officer and Chief Financial Officer of Integrys Energy Group, Inc. (the “Company”), hereby certify, based on our knowledge, that the Quarterly Report on Form 10-Q of the Company for the quarter ended March 31, 2012 (the “Report”) fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Charles A. Schrock
Charles A. Schrock
Chairman, President and Chief Executive Officer

/s/ Joseph P. O’Leary
Joseph P. O’Leary
Senior Vice President and Chief Financial Officer

Date: May 2, 2012

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NWN 10-Q 3/31/2012

Section 1: 10-Q (FORM 10-Q)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2012

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition period from _______ to _______

Commission File No. 1-15973

NW Natural

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Oregon (State or other jurisdiction of incorporation or organization)	**93-0256722** (I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(503) 226-4211**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ]	Smaller reporting company [ ] (Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [X]

At April 30, 2012, 26,800,474 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended March 31, 2012

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

Forward-Looking Statements

This report contains "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "intends," "plans," "seeks," "believes," "estimates," "expects" and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans;
- objectives;
- goals;
- strategies;
- assumptions and estimates;
- future events or performance;
- trends;
- cyclicality;
- earnings and dividends;
- growth;
- customer rates;
- commodity costs;
- operational performance and costs;
- liquidity and financial positions;
- project development and expansion;
- competition;
- storage levels and values;
- procurement, development and production levels of gas supplies and reserves;
- estimated expenditures and investments;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- outcomes and effects of litigation, regulatory actions, and other administrative matters;
- projected status and obligations under retirement plans;
- adequacy of, and shift in mix of, gas supplies;
- approval and adequacy of regulatory deferrals; and
- environmental, regulatory, litigation and insurance costs and recoveries.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks, and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed in our 2011 Annual Report on Form 10-K, Part I, Item 1A. "Risk Factors" and Part II, Item 7. and Item 7A., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures about Market Risk," and in Part I, Items 2 and 3, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk," and Part II, Item 1A, "Risk Factors," herein.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Statements of Comprehensive Income
(Unaudited)

Thousands, except per share amounts	Three Months Ended March 31, 2012	2011
Operating revenues:		
Gross operating revenues	$ 317,494	$ 323,088
Less: Cost of sales	169,771	180,625
Revenue taxes	7,855	7,955
Net operating revenues	139,868	134,508
Operating expenses:		
Operations and maintenance	34,416	31,172
General taxes	8,836	8,165
Depreciation and amortization	17,950	17,309
Total operating expenses	61,202	56,646
Income from operations	78,666	77,862
Other income and expense - net	1,005	1,214
Interest expense - net	11,191	10,449
Income before income taxes	68,480	68,627
Income tax expense	27,873	27,854
Net income	40,607	40,773
Other comprehensive income:		
Amortization of non-qualified employee benefit plan liability, net of taxes of $108 for 2012 and $96 for 2011	166	146
Comprehensive income	$ 40,773	$ 40,919
Average common shares outstanding:		
Basic	26,781	26,670
Diluted	26,862	26,724
Earnings per share of common stock:		
Basic	$ 1.52	$ 1.53
Diluted	$ 1.51	$ 1.53
Dividends declared per share of common stock	$ 0.445	$ 0.435

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2012	March 31, 2011	December 31, 2011
Assets:			
Current assets:			
Cash and cash equivalents	$ 4,031	$ 3,480	$ 5,833
Restricted cash	-	924	-
Accounts receivable	90,817	94,521	77,449
Accrued unbilled revenue	44,444	42,342	61,925
Allowance for uncollectible accounts	(3,694)	(3,821)	(2,895)
Regulatory assets	90,490	48,195	94,673
Derivative instruments	1,824	4,861	2,853
Inventories	61,436	53,266	74,363
Gas reserves	6,732	-	4,463
Income taxes receivable	1,735	23,645	7,045
Other current assets	13,075	13,292	22,980
Total current assets	310,890	280,705	348,689
Non-current assets:			
Property, plant and equipment	2,680,537	2,593,553	2,661,102
Less: Accumulated depreciation	779,683	733,639	767,226
Total property, plant and equipment - net	1,900,854	1,859,914	1,893,876
Gas reserves	61,106	-	47,451
Regulatory assets	368,521	345,452	371,392
Derivative instruments	52	1,560	-
Other investments	67,648	69,501	68,263
Restricted cash	4,000	-	4,000
Other non-current assets	14,191	14,421	12,903
Total non-current assets	2,416,372	2,290,848	2,397,885
Total assets	$ 2,727,262	$ 2,571,553	$ 2,746,574

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2012	March 31, 2011	December 31, 2011
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,798, 26,673, and 26,756 at March 31, 2012 and 2011 and December 31, 2011, respectively	$ 351,005	$ 343,787	$ 348,383
Retained earnings	402,599	385,899	373,905
Accumulated other comprehensive income (loss)	(7,633)	(6,458)	(7,800)
Total common stock equity	745,971	723,228	714,488
Long-term debt	641,700	551,700	641,700
Total capitalization	1,387,671	1,274,928	1,356,188
Current liabilities:			
Short-term debt	113,700	186,435	141,600
Current maturities of long-term debt	-	50,000	40,000
Accounts payable	60,165	71,839	86,300
Taxes accrued	10,509	10,063	10,747
Interest accrued	10,648	11,470	5,857
Regulatory liabilities	50,341	29,016	31,046
Derivative instruments	53,697	25,655	57,317
Other current liabilities	41,503	38,433	41,597
Total current liabilities	340,563	422,911	414,464
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	438,486	396,357	413,209
Regulatory liabilities	288,131	263,876	278,382
Pension and other postretirement benefit liabilities	189,003	132,053	201,530
Derivative instruments	3,947	13,914	6,536
Other non-current liabilities	79,461	67,514	76,265
Total deferred credits and other non-current liabilities	999,028	873,714	975,922
Commitments and contingencies (see Note 13)			
Total capitalization and liabilities	$ 2,727,262	$ 2,571,553	$ 2,746,574

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows
(Unaudited)

Thousands	Three Months Ended March 31, 2012	2011
Operating activities:		
Net income	$ 40,607	$ 40,773
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	17,950	17,309
Deferred tax liabilities	27,089	25,048
Undistributed losses from equity investments	1	25
Non-cash expenses related to qualified defined benefit pension plans	2,007	1,817
Contributions to qualified defined benefit pension plans	(13,800)	(13,645)
Deferred environmental expenditures, net of recoveries	(827)	(1,759)
Other	475	(443)
Changes in assets and liabilities:		
Receivables	6,378	(3,122)
Inventories	12,927	27,119
Taxes accrued	5,072	16,905
Accounts payable	(26,050)	(14,406)
Interest accrued	4,791	6,288
Deferred gas costs	23,663	196
Other - net	13,771	5,959
Cash provided by operating activities	114,054	108,064
Investing activities:		
Capital expenditures	(20,447)	(25,403)
Utility gas reserves	(17,220)	-
Other	(68)	(121)
Cash used in investing activities	(37,735)	(25,524)
Financing activities:		
Common stock issued - net	1,458	(244)
Long-term debt retired	(40,000)	-
Change in short-term debt	(27,900)	(71,000)
Cash dividend payments on common stock	(11,913)	(11,601)
Other	234	328
Cash used in financing activities	(78,121)	(82,517)
Increase (decrease) in cash and cash equivalents	(1,802)	23
Cash and cash equivalents - beginning of period	5,833	3,457
Cash and cash equivalents - end of period	$ 4,031	$ 3,480
Supplemental disclosure of cash flow information:		
Interest paid	$ 6,148	$ 4,162
Income taxes paid	$ 101	$ -

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements
(Unaudited)

1. Organization and Principles of Consolidation

The accompanying consolidated financial statements represent the consolidation of Northwest Natural Gas Company (NW Natural or Company) and all companies that we directly or indirectly control, either through majority ownership or otherwise. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch) and NNG Financial Corporation (NNG Financial). Investments in corporate joint ventures and partnerships that we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method or the cost method, which includes NWN Energy's investment in Palomar Gas Holdings, LLC (PGH). NW Natural and its affiliated companies are collectively referred to herein as "NW Natural." The consolidated financial statements are presented after elimination of all significant intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage business and other non-utility investments and business activities.

Information presented in these interim consolidated financial statements is unaudited, but includes all material adjustments that management considers necessary for a fair statement of the results for each period reported including normal recurring accruals. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2011 Annual Report on Form 10-K (2011 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

2. Significant Accounting Policies Update

Our significant accounting policies are described in Note 2 of the 2011 Form 10-K. There were no material changes to those accounting policies during the three months ended March 31, 2012. The following are current updates to certain critical accounting policy estimates and subsequent events of the Company, and to accounting standards in general.

Regulatory Accounting

In applying regulatory accounting principles in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP), we capitalize or defer certain costs and revenues as regulatory assets and liabilities. At March 31, 2012 and 2011 and at December 31, 2011, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
Thousands	March 31, 2012	March 31, 2011	December 31, 2011
Current:			
Unrealized loss on derivatives[1]	$ 53,697	$ 25,655	$ 57,317
Pension and other postretirement benefit liabilities[2]	15,491	10,988	15,491
Other[3]	21,302	11,552	21,865
Total current	$ 90,490	$ 48,195	$ 94,673
Non-current:			
Unrealized loss on derivatives[1]	$ 3,947	$ 13,914	$ 6,536
Income tax asset	63,452	70,241	65,264
Pension and other postretirement benefit liabilities[2]	166,639	115,490	170,512
Environmental costs[4]	112,297	117,544	105,670
Other[3]	22,186	28,263	23,410
Total non-current	$ 368,521	$ 345,452	$ 371,392

	Regulatory Liabilities		
Thousands	March 31, 2012	March 31, 2011	December 31, 2011
Current:			
Gas costs	$ 35,584	$ 14,144	$ 17,994
Unrealized gain on derivatives[1]	1,824	4,861	2,853
Other[3]	12,933	10,011	10,199
Total current	$ 50,341	$ 29,016	$ 31,046
Non-current:			
Gas costs	$ 14,462	$ 3,932	$ 8,420
Unrealized gain on derivatives[1]	52	1,560	-
Accrued asset removal costs	270,837	256,203	267,355
Other[3]	2,780	2,181	2,607
Total non-current	$ 288,131	$ 263,876	$ 278,382

(1) Unrealized gain and loss on derivatives does not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment mechanism when realized at settlement.
(2) Certain pension and other postretirement benefit liabilities of the utility are approved for regulatory deferral, including amounts recorded to the pension cost balancing account to mitigate the effects of higher and lower pension expenses. Such deferred amounts earn a rate of return or carrying charge (see Note 8).
(3) Other primarily consists of deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.
(4) Environmental costs are related to those sites that are approved for regulatory deferral. In Oregon, we earn a rate of return on amounts paid, whereas amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended. Environmental costs related to Washington were deferred beginning in 2011, with cost recovery and carrying charge to be determined in a future proceeding.

Subsequent Events

There are no subsequent events to report for the period ended March 31, 2012.

New Accounting Standards Update

Adopted Standards

Comprehensive Income. In June 2011, the FASB issued authoritative guidance on the presentation of comprehensive income within the financial statements. An entity can elect to present items of net income and other comprehensive income in one continuous statement—referred to as the statement of comprehensive income—or in two separate, but consecutive, statements. These changes were effective for periods beginning after December 15, 2011. We elected to present net income and other comprehensive income in one continuous statement, "Consolidated Statements of Comprehensive Income."

Multiemployer Pension Plans. In September 2011, the FASB issued authoritative guidance regarding multiemployer pension plan disclosures. The revised standard is intended to provide more information about an employer's financial obligations to a multiemployer pension plan and, therefore, help financial statement users better understand the financial health of all significant plans in which the employer participates. The updated guidance was effective for periods beginning after December 15, 2011, and we elected to early adopted the guidance in our 2011 Form 10-K. Please see Note 9 in our 2011 Form 10-K for more detail.

Fair Value Measurement. In May 2011, the FASB issued amendments to the authoritative guidance on fair value measurement. The amendments are primarily related to disclosure requirements for Level 3 fair value assets and were effective for periods beginning after December 15, 2011. The adoption of this standard did not have a material effect on our financial statement disclosures.

Recent Accounting Pronouncements

Balance Sheet Offsetting. In December 2011, the FASB issued authoritative guidance regarding the offsetting of assets and liabilities on the balance sheet. The revised standard is intended to provide more comparable guidance between the U.S. GAAP and international accounting standards by requiring entities to disclose both gross and net amounts for assets and liabilities offset on the balance sheet as well as other disclosures concerning their enforceable master netting arrangements. This guidance is effective for annual reporting periods beginning after January 1, 2013, and we are currently assessing the impact on our financial statement disclosures.

3. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed using the weighted average number of common shares outstanding plus the potential effects of the assumed exercise of stock options, and payment of estimated stock awards from other stock-based compensation plans that are outstanding, at the end of each period presented. Diluted earnings per share are calculated as follows:

	Three Months Ended March 31,	
Thousands, except per share amounts	2012	2011
Net income	$ 40,607	$ 40,773
Average common shares outstanding - basic	26,781	26,670
Additional shares for stock-based compensation plans[1]	81	54
Average common shares outstanding - diluted	26,862	26,724
Earnings per share of common stock - basic	$ 1.52	$ 1.53
Earnings per share of common stock - diluted	$ 1.51	$ 1.53
[1]Additional shares not included in diluted earnings per share calculation because of antidilutive impact	1,010	2,150

4. Segment Information

We operate in two primary reportable business segments, which we refer to as "utility" and "gas storage." We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as "other." We also refer to our gas storage and other business segments as "non-utility." Our gas storage segment includes: NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy; Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage; the non-utility portion of our underground storage facility in Oregon (Mist); and revenues from third-party asset management services. Our other segment includes NNG Financial and our equity investment in PGH, which is pursuing development of the Palomar pipeline project. For the periods presented, intersegment transactions were insignificant. For further discussion of our segments, see Note 4 in our 2011 Form 10-K.

The following table presents summary financial information about the reportable segments for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31,			
		Non-Utility		
Thousands	Utility	Gas Storage	Other	Total
2012				
Net operating revenues	$ 133,150	$ 6,679	$ 39	$ 139,868
Depreciation and amortization	16,338	1,612	-	17,950
Income from operations	75,964	2,679	23	78,666
Net income	39,791	806	10	40,607
Total assets at March 31, 2012	2,424,583	286,756	15,923	2,727,262
2011				
Net operating revenues	$ 129,162	$ 5,304	$ 42	$ 134,508
Depreciation and amortization	15,914	1,395	-	17,309
Income from operations	76,124	1,716	22	77,862
Net income	40,130	688	(45)	40,773
Total assets at March 31, 2011	2,304,731	244,403	22,419	2,571,553
Total assets at December 31, 2011	$ 2,435,888	$ 294,637	$ 16,049	$ 2,746,574

5. Common Stock

We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2012 to repurchase up to an aggregate of 2.8 million shares, but not to exceed $100 million. No shares of common stock were repurchased pursuant to this program during the three months ended March 31, 2012. Since the plan's inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

6. Stock-Based Compensation

We have several stock-based compensation plans, including a Long-Term Incentive Plan (LTIP), a Restated Stock Option Plan (Restated SOP) and an Employee Stock Purchase Plan. These plans are designed to promote stock ownership in NW Natural by employees and officers. For additional information on our stock-based compensation plans, see Note 6, in the 2011 Form 10-K and current updates provided below.

Long-Term Incentive Plan

Performance-Based Stock Awards. On February 22, 2012, 35,340 performance-based shares were granted under the LTIP, which include a market condition, based on target-level awards and a weighted-average grant date fair value of $53.92 per share. Fair value was estimated as of the date of grant using a Monte-Carlo option pricing model based on the following assumptions:

Stock price on valuation date	$	48.00
Performance term (in years)		3.0
Quarterly dividends paid per share	$	0.445
Expected dividend yield		3.6%
Dividend discount factor		0.9012

Restricted Stock Units. A new form of restricted stock awards was approved by the Board in 2011. Restricted Stock Units (RSUs) are being used instead of the Restated SOP beginning in February of 2012. The current LTIP allows for a variety of awards including RSUs to be granted. RSUs include a performance based threshold and a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of the RSU. On February 22, 2012, RSUs totaling 21,720 were granted with a grant date fair value of $48.00 per share.

Restated Stock Option Plan

As of March 31, 2012, there was $0.8 million of unrecognized compensation cost from grants of stock options in prior years, which is expected to be recognized over a period extending through 2014. No new stock options were granted in the three months ended March 31, 2012.

7. Cost and Fair Value Basis of Debt

Cost and Fair Value of Short-Term Debt

Our short-term debt consists of commercial paper and bank loans with an average maturity date of May 13, 2012 and an outstanding balance of $113.7 million as of March 31, 2012. The fair value of our commercial paper approximates the amortized cost using Level 2 inputs.

Cost of Long-Term Debt

Our utility's long-term debt consists of secured Medium Term Notes (MTNs) with maturity dates ranging from 2014 through 2035, interest rates ranging from 3.176 percent to 9.05 percent, and a weighted-average coupon rate of 5.85 percent. During the three months ended March 31, 2012, we redeemed $40 million of MTNs.

Our gas storage segment's long-term debt consists of $40 million of fixed and variable senior secured notes with a maturity date of November 30, 2016. The $20 million fixed portion of the debt has an interest rate of 7.75 percent, and the $20 million variable portion currently has an interest rate of 7.00 percent. See Note 7 in our 2011 Form 10-K for more detail on long-term debt.

Fair Value of Long-Term Debt

As our outstanding debt does not trade in active markets, we used interest rates of other companies' outstanding debt issuances that actively trade and have similar credit ratings, terms and remaining maturities to estimate the fair value of our long-term debt issuances. These inputs are significant other observable inputs, or Level 2 inputs, in the fair value hierarchy. The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	March 31,		December 31,
Thousands	2012	2011	2011
Carrying amount	$ 641,700	$ 601,700	$ 681,700
Estimated fair value	742,852	680,436	808,724

8. Pension and Other Postretirement Benefit Costs

The following tables provide the components of net periodic benefit cost for our company-sponsored qualified and non-qualified defined benefit pension plans and other postretirement benefit plans:

	Three Months Ended March 31,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2012	2011	2012	2011
Service cost	$ 2,130	$ 1,899	$ 177	$ 168
Interest cost	4,304	4,527	314	344
Expected return on plan assets	(4,638)	(4,456)	-	-
Amortization of net actuarial loss	3,843	2,692	103	68
Amortization of prior service costs	49	88	49	49
Amortization of transition obligations	-	-	103	103
Net periodic benefit cost	5,688	4,750	746	732
Amount allocated to construction	(1,418)	(1,235)	(214)	(226)
Amount deferred to regulatory balancing account[1]	(2,068)	(1,330)	-	-
Net amount charged to expense	$ 2,202	$ 2,185	$ 532	$ 506

[1] Effective January 1, 2011, the Oregon Public Utility Commission (OPUC) approved the deferral of certain pension expenses above or below the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower pension expenses in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return.

Multiemployer and Defined Contribution Plans

In addition to the company-sponsored defined benefit pension plans referred to above, we contribute to a multiemployer pension plan (EIN 94-6076144) for our utility's bargaining unit employees, known as the Western States Office and Professional Employees Pension Fund (Western States Plan), and to defined contribution plans for utility and non-utility employees. The costs of these plans are in addition to pension expense in the table above. Our contributions to the Western States Plan amounted to $0.1 million, and our contributions to the defined contribution plans amounted to $0.7 million and $0.8 million, for the three months ended March 31, 2012 and 2011, respectively. Under the terms of our current collective bargaining agreement, we can withdraw from the Western States Plan at any time. However, if we withdraw and the plan is underfunded, we could be assessed a withdrawal liability. Currently, we have made no decisions to withdraw from the plan. Accordingly, we have not currently recognized these potential withdrawal liabilities on the balance sheet pursuant to accounting rules for multiemployer plans. See Note 9, in the 2011 Form 10-K for more information about these plans.

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

In the three months ended March 31, 2012, we made cash contributions totaling $13.8 million to our qualified defined benefit pension plans. We also expect to make additional contributions of approximately $14 million to these qualified plans over the last nine months of 2012, plus we expect to make ongoing benefit payments under our unfunded, non-qualified pension plans and other postretirement benefit plans.

9. Income Tax

The effective income tax rate for the three months ended March 31, 2012 and 2011 varied from the combined federal and state statutory tax rates principally due to the following:

	March 31,	
	2012	2011
Federal statutory tax rate	35.0%	35.0%
Increase (decrease):		
Current state income tax, net of federal tax benefit	4.6%	4.6%
Amortization of investment and energy tax credits	(0.3) %	(0.4) %
Differences required to be flowed-through by regulatory commissions	1.6%	1.5%
Gains on company and trust-owned life insurance	(0.4) %	(0.2) %
Other - net	0.2%	0.1%
Effective income tax rate	40.7%	40.6%

See Note 10 in our 2011 Form 10-K for more detail on income taxes and effective tax rates.

10. Property, Plant and Equipment

The following table sets forth the major classifications of our property, plant and equipment and accumulated depreciation as of March 31, 2012 and 2011 and December 31, 2011:

	March 31,		December 31,
Thousands	2012	2011	2011
Utility plant in service	$ 2,342,681	$ 2,264,055	$ 2,323,467
Utility construction work in progress	34,903	28,464	36,051
Less: Accumulated depreciation	760,566	720,134	749,603
Utility plant-net	1,617,018	1,572,385	1,609,915
Non-utility plant in service	297,164	292,089	293,205
Non-utility construction work in progress	5,789	8,945	8,379
Less: Accumulated depreciation	19,117	13,505	17,623
Non-utility plant-net	$ 283,836	$ 287,529	$ 283,961
Total property, plant and equipment	$ 1,900,854	$ 1,859,914	$ 1,893,876

11. Gas Reserves and Other Investments

Our gas reserves are stated at cost, net of volumetric regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Other investments include financial investments in life insurance policies, which are accounted for at fair value, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity or cost methods. See Note 12 in the 2011 Form 10-K for more detail on our investments.

Gas Reserves

We entered into agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop and produce physical gas reserves that are expected to supply a portion of NW Natural's utility customers' requirements over 30 years. Encana began drilling in 2011 under these agreements, and we are currently receiving gas from our interests in a section of the gas field. Our cost of gas and the carrying cost of the investment are included in our annual Oregon Purchased Gas Adjustment (PGA) filing and recovered through rates in a manner previously approved by the OPUC. This transaction accounted for approximately 2% of our gas supplies for the three month period ending March 31, 2012. The following table outlines our net investment at March 31, 2012 and 2011 and December 31, 2011:

	March 31,		December 31,
Thousands	2012	2011	2011
Gas reserves, current	$ 6,732	$ -	$ 4,463
Gas reserves, non-current	63,546	-	48,597
Less: Accumulated amortization	2,440	-	1,146
Total gas reserves	67,838	-	51,914
Less: Deferred taxes on gas reserves	22,047	-	15,630
Net investment in gas reserves	$ 45,791	$ -	$ 36,284

Variable Interest Entity (VIE) Analysis. We concluded that the arrangements with Encana qualify as a VIE, but that we are not the primary beneficiary of these activities as defined by the authoritative guidance related to consolidations. We account for our investment in the VIE on the cost basis and it is included under gas reserves on our balance sheet. Our maximum loss exposure related to the VIE is limited to our investment balance.

Palomar

PGH is a development stage variable interest entity. Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH is owned 50 percent by NWN Energy and 50 percent by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

Variable Interest Entity Analysis. As of March 31, 2012, we updated our VIE analysis and reconfirmed that we are not the primary beneficiary of PGH's activities as defined by the authoritative guidance related to consolidations due to the fact that we have a 50 percent share and there are no stipulations that allow disproportionate influence over the entity. Therefore, we account for our investment in PGH and the Palomar project under the equity method, which is included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50 percent owner.

Impairment Analysis. Our investments in nonconsolidated entities accounted for under the equity method, including Palomar, are reviewed for impairment at each reporting period, and following updates to our corporate planning assumptions. When it is determined that a loss in value is other than temporary, a charge is recognized for the difference between the investment's carrying value and its estimated fair value. Fair value is based on quoted market prices when available, or on the present value of expected future cash flows. Differing assumptions could affect the timing and amount of a charge recorded in any period. There have been no significant changes in carrying value or estimated fair value since year end.

Our investment balance in Palomar was $13.5 million at March 31, 2012, which consists of costs related to the east segment. We are continuing to work on development of commercial support and Palomar expects to file a new Federal Energy Regulatory Commission (FERC) certification application to reflect a revised scope based on regional needs for the eastern segment of the proposed Palomar pipeline project. However, if we learn later that the project is not viable or will not go forward, we could be required to recognize a maximum charge of up to approximately $13.2 million based on the current amount of our equity investment net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as required. See Note 12 in our 2011 Form 10-K for more detail on Palomar and our annual impairment analysis.

12. Derivative Instruments

We enter into swap, option and combinations of option contracts for the purpose of hedging natural gas. We primarily use these derivative financial instruments to manage commodity prices related to our natural gas purchase requirements. A small portion of our derivative hedging strategy involves foreign currency exchange transactions related to purchases of natural gas from Canadian suppliers.

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of core utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to these physical gas supply contracts. Derivatives entered into prudently for future gas years prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80 or a 90 percent deferral of any gains and losses as regulatory assets or liabilities, with the remaining 10 or 20 percent recognized in current income. All of our commodity hedging for the 2011-12 gas year was completed prior to the start of the gas year, and these hedge prices were included in our PGA filing.

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments for the three months ended March 31, 2012 and 2011. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to balance sheet accounts in accordance with regulatory accounting standards.

	Three Months Ended			
	March 31, 2012		March 31, 2011	
Thousands	Natural gas commodity (1)	Foreign currency (2)	Natural gas commodity (1)	Foreign currency (2)
Cost of sales	$ (55,894)	$ -	$ (33,750)	$ -
Other comprehensive income	-	126	-	602
Less:				
Amounts deferred to regulatory accounts on balance sheet	55,894	(126)	33,750	(602)
Total impact on earnings	$ -	$ -	$ -	$ -

(1) Unrealized gain (loss) from natural gas commodity hedge contracts is recorded in cost of sales and reclassified to regulatory deferral accounts on the balance sheet.
(2) Unrealized gain (loss) from foreign currency exchange contracts is recorded in other comprehensive income, and reclassified to regulatory deferral accounts on the balance sheet.

No collateral was posted with or by our counterparties as of March 31, 2012 or 2011. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and diversification, we have not been subject to collateral calls in 2011 or 2012. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current contracts outstanding, which reflect unrealized losses of $55.8 million at March 31, 2012, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various downgrade credit rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$ -	$ 12,785	$ 6,805	$ 40,441
Without Adequate Assurance Calls	$ -	$ -	$ -	$ 4,292	$ 32,928

In the three months ended March 31, 2012 and 2011, we realized net losses of $29.4 million and $20.9 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas. The exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of our customers. For more information on our derivative instruments, see Note 13 in our 2011 Form 10-K.

Fair Value

In accordance with fair value accounting, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation techniques include natural gas futures, volatility, credit default swap spreads and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at March 31, 2012. As of March 31, 2012 and 2011 and December 31, 2011, the fair value was a liability of $55.8 million, $33.1 million and $61.0 million, respectively, using significant other observable, or Level 2, inputs. We have used no Level 3 inputs in our derivative valuations. We also did not have any transfers between Level 1 or Level 2 during the three months ended March 31, 2012 and 2011.

13. Commitments and Contingencies

Environmental Matters

We own, or previously owned, properties that may require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study and evaluate the extent of our potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated.

We regularly review our environmental liability for each site where we may be exposed to remediation responsibilities, but the costs are difficult to estimate. A number of steps are involved in each environmental remediation effort, including site investigations, remediation, operations and maintenance, monitoring and site closure. Site investigations and remediation efforts often develop slowly over many years. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course and scope of the effort and ultimately also the cost. Many of these steps are dependent upon the approval and direction of federal and state environmental regulators whose policies, determinations and directions may change over time creating further uncertainty as to the timing and scope of remediation activities. In certain cases there are a number of other potentially responsible parties in addition to us, each of which may influence the course and scope of the remediation effort. The allocation of liabilities among the potentially responsible parties is subject to dispute and uncertainty at this time with respect to the sites noted below. These disputes could lead to adversarial administrative proceedings or litigation, with uncertain outcomes.

We estimate the range of loss for environmental liabilities using current technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is an estimate within a range of possible losses that is more likely than other cost estimates within that range, we record the liability at the lower end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to uncertainty concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives. The status of each of the sites currently under investigation is provided below.

Portland Harbor site. In 1998, the Oregon Department of Environmental Quality (ODEQ) and the Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor). Since then, EPA has extended the Portland Harbor site to approximately 11 miles of the Willamette River. The Portland Harbor site is adjacent to two upland sites owned by NW Natural that are discussed below as the Gasco upland and Siltronic upland sites. The Portland Harbor was listed by the EPA as a Superfund site in 2000, and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties (the Lower Willamette Group or LWG) to fund the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). The LWG submitted the draft Final Portland Harbor Remedial Investigation to EPA in 2011. The LWG submitted the draft Feasibility Study (FS) to EPA in March 2012. The EPA will use the information in the RI/FS to select a cleanup plan for the Portland Harbor Superfund Site. The draft FS provides a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is $169 million to $1.8 billion. NW Natural's potential liability is a portion of the costs of the remedy EPA ultimately selects for the entire Portland Harbor Superfund site. The costs of that remedy is expected to be allocated among more than 100 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with EPA to evaluate and design specific remedies for sediments adjacent to the Gasco upland and Siltronic upland sites, discussed below. The Gasco/Siltronic Sediments is part of the Portland Harbor Superfund site. NW Natural intends to submit a draft Engineering Evaluation/Cost Analysis (EE/CA) to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. The EE/CA will provide a variety of remedial alternatives for the sediments at this site. The alternatives provided in the EE/CA are based on EPA requirements to develop costs for the various remedies described therein. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA range from $34 million to $350 million. After the EPA determines an appropriate alternative from the EE/CA, a remedial design will be produced. We have recorded a liability of $34.0 million for the sediment clean-up, which reflects the low end of the EE/CA range. We have recorded an additional liability of $12.1 million for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight through the clean-up. At this time, we believe the sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above. We accrued at the low end because no amount within the range is considered to be more likely than another.

Portland Harbor RI/FS and natural resource damage claims. NW Natural incurs costs related to our membership in the Lower Willamette Group which is performing the RI/FS for EPA. NW Natural also incurs costs related to natural resource damages. In 2008, the Portland Harbor Natural Resource Trustee Council advised a number of potentially responsible parties that it intended to pursue natural resource damage claims at the Portland Harbor Superfund Site. The Company and other parties have signed a cooperative agreement with the Natural Resource Trustees to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. As of March 31, 2012, we have an accrued liability of $4.9 million for these claims, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated at this time. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor.

Gasco upland site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site). The Gasco upland site is adjacent to the Portland Harbor site described above and has been under investigation by us for environmental contamination under the ODEQ Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site. In June 2003, we filed a Feasibility Scoping Plan which outlined a range of remedial alternatives for the most contaminated portion of the Gasco upland site. In December 2004, we submitted an Ecological and Human Health Risk Assessment to ODEQ, and in May 2007 we completed a revised Remedial Investigation Report and submitted it to ODEQ for review. The liability accrued at March 31, 2012 for the Gasco upland site is $9.3 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

In 2007, we also submitted a Focused Feasibility Study (FFS) for the groundwater source control portion of the Gasco site, which ODEQ conditionally approved in March 2008, subject to the submission of additional information. We provided that information to ODEQ and are now working with the agency on the final design for the source control system. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding remediation, we have estimated a range of liability between $11 million and $30 million, for which we have recorded an accrued liability of $11.6 million at March 31, 2012. The estimated range of liability will be reassessed when ODEQ makes a final source control design decision.

Siltronic upland site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic upland site). The Siltronic upland site is also adjacent to the Portland Harbor site, but not included in the range of remedial costs for the Portland Harbor site. We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ. The liability accrued at March 31, 2012 for the Siltronic site is $1.1 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. In early 2008, we received notice that this site was added to the ODEQ's list of sites in which releases of hazardous substances have been confirmed. ODEC has also added this site to its list of sites where cleanup is necessary. We are currently performing an environmental investigation of the property under the ODEQ's Independent Cleanup Pathway. As of March 31, 2012, we have a liability accrued of $0.4 million for investigation at this site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. It is near but outside the geographic scope of the current Portland Harbor site sediment studies. The EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank adjacent to where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. As the Front Street site is upstream from the Portland Harbor site, the EPA agreed that it could be managed separately from the Portland Harbor site under ODEQ authority. Work plans for source control investigation and a historical report were submitted to ODEQ and initial studies were completed. In 2010, ODEQ required additional studies which are underway. As of March 31, 2012, we have an estimated liability accrued of $1.5 million for the study of the sediments and riverbank groundwater and soils at the site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Oregon Steel Mills site. See "Legal Proceedings," below.

Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at March 31, 2012 and 2011 and December 31, 2011:

	Current Liabilities			Non-Current Liabilities		
Thousands	Mar. 31, 2012	Mar. 31, 2011	Dec. 31, 2011	Mar. 31, 2012	Mar. 31, 2011	Dec. 31, 2011
Portland Harbor site:						
Gasco/Siltronic Sediments	$ 2,459	$ 1,049	$ 1,614	$ 43,655	$ 29,996	$ 35,797
Other Portland Harbor	1,400	2,314	1,893	3,547	5,829	7,066
Gasco site	13,197	12,574	14,092	7,689	6,103	8,900
Siltronic upland site	478	730	887	588	291	128
Central Service Center site	-	5	-	424	501	495
Front Street site	1,131	-	1,697	395	947	-
Other sites	-	-	-	116	117	120
Total	$ 18,665	$ 16,672	$ 20,183	$ 56,414	$ 43,784	$ 52,506

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the OPUC approved our request to defer unreimbursed environmental costs associated with certain named sites, including those described above. Beginning in 2006, the OPUC granted us additional authorization to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and interest accrual has been extended through January 2013. In addition, beginning in 2011, the Washington Utilities and Transportation Commission (WUTC) authorized the deferral of certain environmental costs associated with services provided to Washington customers. Environmental costs related to Washington are being deferred as of January 26, 2011 with cost recovery to be determined in a future proceeding.

On a cumulative basis, we have recognized a total of $129.7 million for environmental costs, including legal, investigation, monitoring and remediation costs, and $4.9 million paid and expensed prior to regulatory deferral order approval. At March 31, 2012, we had a regulatory asset of $112.3 million.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Item 3. Legal Proceedings in the 2011 Form 10-K). NW Natural seeks damages in excess of $50 million in losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future. In December 2011, NW Natural reached a settlement with Associated Electric and Gas Insurance Services Limited and dismissed its claims against that insurer in the litigation.

Our regulatory recovery of environmental cost deferrals may be initiated when rates go into effect for the Oregon general rate case; however, because the rate case proceeding is ongoing, and because the ultimate amounts collected will depend upon future insurance recoveries and future expenditures, we are not currently able to estimate the amount of recovery expected through the implementation of new rates.

Legal Proceedings

We are subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, we do not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows as we would expect to receive insurance recovery or rate recovery.

Oregon Steel Mills site. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of Northwest Natural Gas Company's (NW Natural) financial condition, including the principal factors that affect results of operations. The disclosures contained in this report refer to our consolidated activities for the three months ended March 31, 2012 and 2011. Unless otherwise indicated, references below to "Notes" are to the Notes to Consolidated Financial Statements in this report. A significant portion of our business results are seasonal in nature, and as such the results of operations for this three month period are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2011 Annual Report on Form 10-K (2011 Form 10-K).

The consolidated financial statements include the accounts of NW Natural and its direct and indirect wholly-owned subsidiaries which include: NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch) and NNG Financial Corporation (NNG Financial). These statements also include accounts related to our equity investment in Palomar Gas Holdings, LLC (PGH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary Palomar Gas Transmission LLC (Palomar). These accounts make up our regulated local gas distribution business, our regulated gas storage businesses, and other regulated and non-regulated investments primarily engaged in energy-related businesses. In this report, the term "utility" is used to describe our regulated gas distribution business (local distribution company), and the term "non-utility" is used to describe our regulated gas storage businesses (gas storage) as well as our other regulated and non-regulated investments and business activities (other). For further information on our business segments, see Note 4.

In addition to presenting results of operations and earnings amounts in total, certain financial measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on consolidated earnings. All references in this section to earnings per share are on the basis of diluted shares (see Part II, Item 8., Note 3, "Earnings Per Share," in our 2011 Form 10-K). We use such non-GAAP measures (i.e. measures not based on generally accepted accounting principles) in analyzing our financial performance and believe that they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

Executive Summary

Highlights of consolidated results for the first quarter of 2012 as compared to the same period in 2011 include:

- Consolidated net income of $40.6 million or $1.51 per share in the first quarter of 2012, as compared to $40.8 million or $1.53 in the first quarter of 2011;
- Net income from utility operations decreased $0.3 million, from $40.1 million in 2011 to $39.8 million in 2012;
- Net income from gas storage operations increased $0.1 million, from $0.7 million in 2011 to $0.8 million in 2012;
- Net operating revenues (margin) increased $5.4 million or 4 percent over 2011, with utility margin up $4.0 million and gas storage margin up $1.4 million;
- Operating expenses increased $4.6 million or 8 percent over 2011, primarily due to higher operations and maintenance expense and higher general tax expense;
- Interest expense increased $0.7 million or 7 percent over 2011 due to senior secured notes issued by Gill Ranch late in 2011;
- Cash flow from operating activities was $114.1 million, an increase of $6.0 million or 6 percent over the same period in 2011;
- Utility customers increased by approximately 5,300 over the last 12 months, for an annual growth rate of 0.8 percent compared to 0.9 percent a year ago; and
- NW Natural was ranked as the top gas utility in the West, and second highest in the nation, in the 2012 J.D. Power & Associates Business Customer Satisfaction Survey.

Issues, Challenges and Performance Measures

Economic environment. Weakness in local, national and global economies continues to impact utility customer growth, business demand for natural gas and market prices for gas storage. Our utility's customer growth rate remained relatively flat for the third year in a row, with an annual growth rate of 0.8 percent for the period ended March 31, 2012, compared to 0.8 percent for March 31, 2011 and 0.7 percent for March 31, 2010. The local economy is beginning to show signs of a slow recovery, with unemployment rates in Oregon and southwest Washington declining from over 10 percent during 2011 to under 9 percent early in 2012, and with industrial usage of natural gas increasing 4 percent in 2012 over 2011. We believe our utility is well positioned to add customers and to serve increasing industrial demand as the economy recovers because of low and stable natural gas prices, our relatively low market penetration, our focus on converting homes and businesses to natural gas, and the potential for environmental initiatives that could favor natural gas use in our region.

Managing gas prices and supplies. Our gas acquisition and management strategy is to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so that we can effectively manage costs, reduce price volatility for customers, and maintain a competitive advantage. With recent developments in drilling technologies and substantial access to gas supplies from shale formations around the U.S. and in Canada, the current outlook for North American natural gas supply is strong and should remain that way well into the future. The abundance of gas suggests continued lower and more stable gas prices, subject to a regulatory environment that continues to support hydraulic fracturing and other drilling technologies.

Our utility's Purchased Gas Adjustment (PGA) mechanisms in Oregon and Washington, along with our gas price hedging strategies which include gas reserves and gas storage inventories, enable us to reduce earnings exposure for the company and secure lower gas costs for customers. These lower gas prices, coupled with our focus on customer service and cost-effective energy efficiency programs, can help strengthen natural gas' competitive advantage over other energy sources in key markets.

Each year we typically hedge about 75 percent of our utility's annual sales requirements based on normal weather. For the current gas contract year (November 1, 2011 – October 31, 2012), we were roughly 51 percent hedged with financial swap and option contracts and 24 percent hedged with physical gas supplies. The physical supplies consisted of a combination of gas inventories in storage, gas production from the Mist area which we buy at pre-determined prices, and gas production from an investment we made in gas reserves with Encana Oil & Gas (USA) Inc. (Encana). The gas reserves with Encana relate to a new investment we made beginning in 2011, whereby we own working interests in certain leases in Encana's Jonah gas field located in Rock Springs, Wyoming. For a further discussion of gas reserves, see "Investments in Gas Reserves" under "Strategic Opportunities" below and "Gas Reserves" under "Rate Mechanisms" below.

Besides the amount hedged for the current gas contract year, we are also hedged at approximately 32 percent for the 2012-13 gas year and between 9 and 14 percent hedged for annual requirements over the following five gas years. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather and economic conditions. In addition, our storage inventory levels may increase or decrease based on storage expansion or storage recall by the utility. The Company added approximately 1 Bcf to its off-system storage capacity by entering into a 3-year contract with a third-party for natural gas storage located in Canada. Injections are scheduled to begin April 2012. We expect recovery of our demand charges and other costs through our normal PGA mechanism. As for gas reserves, these levels are estimates of production, which are subject to change based on possible unforeseen events including the impact from the pace of drilling activity and the volume of production from each well.

Although less expensive and more stable gas prices provide opportunities to manage costs for our utility customers, they also present challenges for our gas storage businesses by lowering the price of, and reducing the demand for, storage services. Consequently, our ability to sign longer-term storage contracts with customers at favorable prices affects our ability to improve financial results, but we remain committed to find opportunities for lowering costs and to develop enhanced services for customers.

Environmental clean-up costs. We continue to accrue all material loss contingencies related to environmental sites for which we are responsible. Due to numerous uncertainties surrounding the nature of environmental investigations and the development of remediation solutions approved by regulatory agencies, actual costs could vary significantly from our loss estimates. As a regulated utility, we have been allowed to defer certain costs pursuant to regulatory decisions. We currently have regulatory authority to defer certain environmental costs, and to seek recovery of those costs in future customer rates. However, we are expected to pursue recovery from insurance policies first, and to seek recovery from customers only for amounts not recovered from insurance. Ultimate recovery of environmental costs, either from regulated utility rates or from insurance, will depend on our ability to effectively manage costs and demonstrate that costs were prudently incurred. Recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable.

See Results of Operations—Regulatory Matters—Rate Mechanisms—Regulatory Recovery for Environmental Costs below, Note 13 in this report and Note 15 in our 2011 Form 10-K.

Performance measures. In order to deal with the challenges affecting our businesses, we annually review and update our strategic plan to map out a course for the next several years. Our plan includes: further improving our utility gas distribution system; enhancing utility services and operations; optimizing and growing our non-utility gas storage businesses; investing in natural gas infrastructure projects when necessary to support the energy needs of our region; and maintaining a leadership role within the gas utility industry by addressing long-term energy policies and pursuing business opportunities that support clean energy technologies. We intend to measure our performance and monitor progress on relevant metrics including, but not limited to: earnings per share growth; total shareholder return; return on invested capital; utility return on equity; utility customer satisfaction ratings; utility margin; utility capital and operations and maintenance expense per customer; and earnings before interest, taxes, depreciation and amortization (EBITDA).

Strategic Opportunities

Business process improvements. We continue to evaluate, develop and implement business strategies to improve operational efficiencies and respond to economic and competitive challenges. Over the past several years, we focused our efforts on developing, integrating, consolidating and streamlining operations, while supporting our employees with new training and new technology tools.

Since 2006, we reduced staffing levels in response to work load declines related to the low customer growth environment and efficiency improvements, resulting in a reduction of full-time, utility positions from over 1,300 in early 2006 to about 1,050 at the end of 2011. Technology investments, workforce reductions and other initiatives have contributed to a significant increase in efficiency. We also continue to improve the quality and integrity of our buildings and pipeline infrastructure. The number of utility customers served per operating employee increased by 32 percent, from 738 at the end of 2005 to 975 at the end of 2011. We expect these efforts to contribute to long-term operational efficiencies and lower operating and capital costs throughout NW Natural. We remain committed to increasing shareholder value and we continue to look for new ways to improve our business effectiveness as service demands and federal safety requirements increase.

Gas storage development. We currently own and operate two underground gas storage facilities—the Mist facility in Oregon and the Gill Ranch facility in Fresno, California. Our Mist facility currently consists of 16 Bcf of available storage capacity, with 10 Bcf allocated to the utility business and 6 Bcf allocated to the gas storage business. Our wholly-owned subsidiary, Gill Ranch, holds a 75 percent undivided ownership interest in the Gill Ranch facility; Pacific Gas and Electric Company (PG&E) owns the other 25 percent interest. Currently, we have 15 Bcf of available storage capacity for the gas storage business, along with 27 miles of gas transmission pipeline capacity connecting the Gill Ranch facility to an interconnect on PG&E's transmission system. Future expansion is possible at both the Mist and Gill Ranch storage facilities. For more information, see Note 4 in this report and Part II, Item 7., "2012 Outlook—Strategic Opportunities," in our 2011 Form 10-K.

Due to an abundant supply of natural gas and lower, more stable prices in North America, storage values are expected to remain relatively low in the near term, which will likely affect the prices at which Gill Ranch is able to contract. Gas prices recently hit a 10-year low, and this has resulted in certain natural gas producers reducing their levels of exploration and production. At the same time, we expect these lower gas prices to increase demand for natural gas as the lower pricing provides a competitive advantage over alternative energy sources including the potential demand for exporting natural gas. Combined, these forces may ultimately result in upward pressure on gas prices and return some price volatility to natural gas markets.

Our storage facilities position us well to capitalize on rising demand for natural gas, increasing gas prices or greater market volatility because storage operations benefit from seasonal swings in commodity prices and market volatility. Additionally, if market demand increases and we are able to obtain regulatory permits and project financing, we have the ability to expand the Gill Ranch facility beyond its current capacity without further expansion of our gas transmission pipeline. We estimate that the current Gill Ranch storage facility could support an aggregate storage capacity of around 40 Bcf with certain infrastructure modifications, of which we would have the rights to 50 percent of the total.

The Pacific Northwest storage markets also are impacted by lower gas prices and lack of gas price volatility, although less than California markets primarily because of fewer regional competitors. Nevertheless, we continue to plan for expansion of our gas storage facilities at Mist in anticipation of increased natural gas demand for electric generation in the Pacific Northwest. Currently we do not have a set timeline for development, but we believe the earliest timeframe for completing the next Mist expansion is 2016. In the meantime, we expect to continue working on preliminary design and scope of the next expansion, which will likely include the development of storage wells, a second compression station and additional pipeline gathering facilities that would enable not only the next expansion but future expansions as well.

Pipeline diversification. Currently, our utility operations and gas storage operations at Mist depend on a single bi-directional interstate transmission pipeline to ship customer supplies. Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a gas transmission pipeline that would provide a new interconnection with our utility distribution system. PGH is owned 50 percent by our NWN Energy subsidiary and 50 percent by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. The Palomar pipeline was originally proposed with an east and a west segment, but currently Palomar's plan is to design and develop an east-only pipeline to serve our utility customers as well as growing natural gas markets in Oregon and other parts of the Pacific Northwest.

Palomar has negotiated a non-binding memorandum of understanding (joint agreement) with The Williams Companies' Northwest Pipeline (Northwest Pipeline), which contemplates Northwest Pipeline becoming a part owner in the Palomar project. This joint agreement would consolidate the region's efforts to develop a cross-Cascades pipeline around the use of the Palomar route. Northwest Pipeline is the owner and operator of the single bi-directional interstate transmission pipeline that connects with NW Natural's utility distribution system.

The proposed Palomar pipeline would be regulated by Federal Energy Regulatory Commission (FERC). In March 2011, Palomar withdrew its original application with FERC, but at the same time informed FERC that it intended to file a new application with a modified scope that excluded the western segment, after it has conducted a new open season to obtain commercial support for the eastern segment. The timing for construction of the Palomar pipeline is expected depends on regulatory permits and determining commercial support from shippers.

Gas reserves. In addition to hedging gas prices with financial swap and option contracts, we signed an agreement with Encana in 2011 to acquire physical gas supplies to meet a portion of our utility customers' requirements over 30 years. During the first 10 years, we forecast the volumes of gas received under the Encana agreement to provide approximately 8 to 10 percent of the average annual requirements of our utility customers. Under the agreement, we expect to invest approximately $45 million to $55 million per year for five years, subject to certain NW Natural rights to terminate the agreement, with our total investment expected to be about $250 million. We pay a fixed portion of drilling costs per well, and Encana assigns to us working interests in leases to certain sections of the Jonah gas field, located near Rock Springs, Wyoming. These sections include both future and currently producing wells. The working interests entitle us to receive a portion of the gas produced in the assigned sections. Operation of the wells are governed by a joint operating agreement under which Encana is the operator, and we pay our proportionate share of the operating costs. See Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves below and Part II, Item 7., "2012 Outlook—Strategic Opportunities," in our 2011 Form 10-K.

Consolidated Earnings and Dividends

The primary factors contributing to the decrease in first quarter consolidated net income were:

- a $5.4 million increase in net operating revenue (margin) primarily due to an increase from the utility's residential and commercial customers, an increase from the utility's incentive sharing related to gas cost savings, and an increase from gas storage at Gill Ranch;
- a $3.2 million increase in operations and maintenance expense primarily related to increases in utility payroll, utility employee benefit costs, utility training costs, and Oregon rate case expenses;
- a $0.7 million increase in general taxes, primarily related to Gill Ranch property taxes;
- a $0.7 million increase in depreciation and amortization related to capital asset additions at both the utility and Gill Ranch; and
- a $0.7 million increase in interest expense primarily related to the new debt issuance at Gill Ranch in late 2011.

Dividends paid on our common stock were 44.5 cents per share in the first quarter of 2012, compared to 43.5 cents per share in the first quarter of 2011. The Board of Directors declared a quarterly common stock dividend of 44.5 cents per share, payable on May 15, 2012, to shareholders of record on April 30, 2012. The current indicated annual dividend rate is $1.78 per share.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (GAAP), management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management's most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions. Our most critical estimates and judgments include accounting for:

- regulatory cost recovery and amortizations;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes; and
- environmental contingencies.

There have been no material changes to the information provided in the 2011 Form 10-K with respect to the application of critical accounting policies and estimates (see Part II, Item 7., "Application of Critical Accounting Policies and Estimates," in the 2011 Form 10-K). For an update of environmental disclosures see Note 13.

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 2.

Results of Operations

Regulatory Matters

Regulation and Rates

Utility. Our utility business is subject to regulation with respect to, among other matters, rates and systems of accounts set by the Oregon Public Utility Commission (OPUC), Washington Utilities and Transportation Commission (WUTC), and FERC. The OPUC and WUTC also regulate the issuance of securities by our utility. In 2011, approximately 90 percent of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 10 percent from Washington customers. Future earnings and cash flows from utility operations will largely be determined by rate cases in Oregon and Washington, but will also be affected by the economies in Oregon and Washington, by the pace of customer growth in the residential and commercial markets, and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets.

Gas Storage. Our gas storage business is subject to regulation with respect to, among other matters, issuance of securities and systems of accounts set by the OPUC, California Public Utilities Commission (CPUC), and FERC. The OPUC and FERC regulate our Mist gas storage business under a maximum cost-based rate model, whereas the CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2011, approximately 65 percent of our storage revenues were derived from OPUC and FERC approved cost-based rates, and approximately 35 percent were from California approved market-based rates.

See Part II, Item 7., “Results of Operations—Regulatory Matters,” in the 2011 Form 10-K.

Oregon General Rate Case

On December 30, 2011, we filed an application for a general rate increase with the OPUC. In the filing, we requested an increase in authorized annual Oregon jurisdictional revenues of $43.7 million, equivalent to a rate increase of 6.2 percent. The amount and percent of the requested rate increase includes an estimated $15.1 million that represents the cumulative effect of declining use per customer. This amount is currently recovered in customers’ rates through the Company’s conservation tariff mechanism, which has been in place since 2003. Our requested increase also includes costs related to pension contributions and additional utility services. The filing also requests an authorized overall rate of return on capital of 8.28 percent, with a return on common stock equity (ROE) of 10.3 percent and a capital structure of 50 percent common equity. In addition, we have requested the establishment of rate recovery mechanisms for deferred costs related to our environmental liabilities. The filing also requests rate redesign for residential customers with a higher fixed fee, which would effectively combine and incorporate the effects of the weather normalization and decoupling tariffs in the new fixed fee amount. The new rates are requested to be effective by November 1, 2012.

On May 3, 2012, several parties involved in NW Natural’s general rate case filed their testimony, which represents their first filing in the formal administrative proceeding through which the OPUC determines rate cases. These included the Staff of the OPUC, the Citizen’s Utility Board (CUB), and the Northwest Industrial Gas Users (NWIGU). In its testimony, the OPUC Staff recommended a revenue requirement reduction of $10.7 million, or 1.5 percent, compared to our requested $43.7 million increase. Staff’s testimony is based on a 7.56 percent overall cost of capital including a 9.2 percent return on common equity, and reductions to various operation and maintenance (O&M) expenses and capital additions requested. These parties also recommended certain modifications to our proposed environmental cost recovery mechanism, modifications to an existing allocation of revenues to customers from our interstate gas storage operations and denial of our request for recovery of certain costs related to our contributions covering employee pension benefits. The filings made by CUB and NWIGU overlap with Staff’s proposals in some areas while also recommending additional reductions to O&M and capital additions. The Company disagrees with the recommendations made and will be filing testimony rebutting these recommendations in June.

Throughout the formal administrative proceeding, NW Natural and the parties have the opportunity to engage in settlement discussions regarding any or all of the issues involved in the proceeding. We have engaged in such discussions during scheduled settlement conferences. We are unable at this time to predict the outcome of this rate proceeding, or to predict which, if any, issues will be presented to the OPUC as part of a contested proceeding or as part of a settlement proposal.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including gas prices under spot purchases as well as contract supplies, gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories and gas reserves, interstate pipeline demand costs, the application of temporary rate adjustments which amortizes balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

Effective November 1, 2011, the OPUC and WUTC approved PGA rate changes to decrease the average monthly bills of Oregon and Washington residential customers by 2 percent. This was our third consecutive year of PGA rate decreases, and cumulatively our average utility residential customer bills declined 20 percent in Oregon and 26 percent in Washington since 2008.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80 percent or 90 percent deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20 percent or 10 percent of the difference between actual and estimated gas costs, respectively. Under the Washington PGA mechanism, we defer 100 percent of the higher or lower actual gas costs, and those gas cost differences are normally passed on to customers through the annual PGA rate adjustment. See “Customer Credits for Gas Cost Incentive Sharing” below for a discussion of our utility’s early refund proposal to customers of deferred gas cost savings from November 1, 2011 through March 31, 2012.

In addition to the gas cost incentive sharing mechanism, we are subject to an annual earnings test to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33 percent of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80 percent deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90 percent deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90 percent deferral option for the 2009-10, the 2010-2011 and the 2011-2012 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2010 and 2011, the ROE threshold after adjustment for long-term interest rates was 11.02 percent and 10.92 percent, respectively. We refunded $0.2 million to customers in the current PGA for the 2010 utility earnings test. Based on utility results for 2011 we accrued an amount for potential refund to customers in the future PGA’s.

Environmental Costs. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue a carrying cost on environmental costs paid, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and accrual of carrying costs was extended through January 2013. See Note 13 for further discussion of our regulatory and insurance recovery of environmental costs.

The WUTC has also authorized the deferral of environmental costs, if any, that are incurred in connection with services provided to Washington customers. The order granting approval of that request was effective January 26, 2011.

Pension Deferral. Effective January 1, 2011, the OPUC approved our request to defer the annual accounting expense for qualified defined benefit pension plans above the amount set in rates in our last general rate case. The recovery of these deferred pension costs will be through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return, which is currently 8.62 percent. The reduction to operations and maintenance expense in 2011 was $6.0 million. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities using a number of key assumptions, as well as being affected by pension contributions by the company. We estimate pension expense deferrals totaling $8 million to $9 million in 2012, with $2.1 million being deferred for the three months ended March 31, 2012.

Customer Credits for Gas Cost Incentive Sharing. For the period between November 1, 2011 and March 31, 2012, our actual gas costs were significantly lower than the gas costs currently embedded in customer rates. As a result, our PGA incentive sharing mechanism recorded 90 percent of gas cost savings during this period, attributed to Oregon customers, and 100 percent of the savings attributed to Washington customers to a regulatory account for credit to customers (see "Purchased Gas Adjustment," above). Ordinarily, these credits would be included in customer rates starting in November under the next year's PGA filing, but in April 2012 the company requested regulatory approval to immediately refund $35.1 million and $4.2 million to our Oregon and Washington customers, respectively, through billing credits. If approved, we intend to credit these amounts to customer bills starting in June of 2012.

Customer Credits for Gas Storage Sharing. In April 2012, the company requested regulatory approval to provide its Oregon utility customers with a $9.2 million interstate storage credit from our regulatory incentive sharing mechanism related to interstate gas storage and asset management services. If approved, we intend to credit this amount to customer bills starting in June of 2012.

For a discussion of other rate mechanisms, including but not limited to our system integrity program, see Part II, Item 7., "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2011 Form 10-K.

Business Segments - Utility Operations

Our utility margin results are largely affected by customer growth and, to a certain extent, by changes in volume due to weather and customers' gas usage patterns because a significant portion of our margin revenues are derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff, which adjusts margin revenues to offset changes resulting from increases or decreases in average use by residential and commercial customers. We also have a weather normalization tariff in Oregon, which adjusts customer bills up or down to offset changes in margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce the volatility of our utility's earnings and customer charges. For more information on our conservation and weather normalization tariffs, see discussion under "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2011 Form 10-K.

For the three months ended March 31, 2012, utility operations contributed net income of $39.8 million or $1.48 per share, compared to $40.1 million or $1.50 per share for the same period of 2011. Total utility volumes sold and delivered for the three months ended March 31, 2012 increased by 2 percent compared to the same period for 2011 primarily due to an increase in all three customer categories (i.e. residential, commercial and industrial). Total utility margin increased by $4 million, or 3 percent primarily due to increases in residential and commercial customer margins totaling $1.7 million, including the effects of conservation and weather normalization adjustments, and an increase in gas cost incentive sharing gains of $1.6 million.

Our weather normalization mechanism adjusted residential and commercial margins down by $3.8 million in the three months ended March 31, 2012 based on temperatures that were 4 percent colder than average, compared to a margin decrease of $5.9 million last year when temperatures were 6 percent colder than average. Our decoupling mechanism adjusted residential and commercial margins up by $6.7 million in the three months ended March 31, 2012, compared to a margin increase of $8.7 million in the comparable period last year.

The following table summarizes the composition of gas utility volumes, revenues and margin. Certain amounts in prior year balances under the utility margin section of the table have been reclassified to conform with the current year's presentation. These reclassifications reflect amounts moved from other margin adjustments into residential, commercial and industrial categories where amounts were assignable to a specific customer category. Utility margin in total was not affected by the reclassifications.

Thousands, except degree day and customer data	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Favorable/ (Unfavorable) 2012 vs. 2011
Utility volumes - therms:			
Residential sales	176,037	174,704	1,333
Commercial sales	100,122	99,177	945
Industrial - firm sales	10,619	10,864	(245)
Industrial - firm transportation	38,851	36,482	2,369
Industrial - interruptible sales	17,730	17,237	493
Industrial - interruptible transportation	64,800	62,950	1,850
Total utility volumes sold and delivered	408,159	401,414	6,745
Utility operating revenues - dollars:			
Residential sales	$ 194,839	$ 198,837	$ (3,998)
Commercial sales	92,175	94,768	(2,593)
Industrial - firm sales	8,309	8,845	(536)
Industrial - firm transportation	1,908	1,746	162
Industrial - interruptible sales	10,048	10,327	(279)
Industrial - interruptible transportation	2,046	2,316	(270)
Regulatory adjustment for income taxes paid(1)	-	286	(286)
Other revenues	1,435	602	833
Total utility operating revenues	310,760	317,727	(6,967)
Cost of gas sold	169,755	180,610	10,855
Revenue taxes	7,855	7,955	100
Utility margin	$ 133,150	$ 129,162	$ 3,988
Utility margin:(2)			
Residential sales	$ 85,608	$ 84,252	$ 1,356
Commercial sales	32,965	32,558	407
Industrial - sales and transportation	7,636	7,610	26
Miscellaneous revenues	1,595	1,584	11
Gain from gas cost incentive sharing	2,637	1,035	1,602
Other margin adjustments	(133)	(1,027)	894
Margin before regulatory adjustments	130,308	126,012	4,296
Weather normalization adjustment	(3,815)	(5,861)	2,046
Decoupling adjustment	6,657	8,725	(2,068)
Regulatory adjustment for income taxes paid(1)	-	286	(286)
Utility margin	$ 133,150	$ 129,162	$ 3,988
Customers - end of period:			
Residential customers	617,665	612,738	4,927
Commercial customers	63,210	62,800	410
Industrial customers	919	908	11
Total number of customers - end of period	681,794	676,446	5,348
Actual degree days	1,954	1,974	
Percent colder than average weather(3)	4%	6%	

(1) Regulatory adjustment for income taxes paid is described below.
(2) Amounts reported as margin for each category of customers are net of cost of gas sold and revenue taxes.
(3) Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

Residential and Commercial Sales

The primary changes that impacted margin from residential and commercial sales for the three months ended March 31, 2012 compared to March 31, 2011 were as follows:

- utility sales volumes were 1 percent higher, primarily reflecting residential and commercial customer growth of 0.8 percent and increased demand from customers;
- utility operating revenues decreased $6.6 million or 2 percent primarily due to lower customer billing rates tied to PGA prices decreases, partially offset by higher volumes; and
- utility margin increased $1.7 million or 1 percent primarily reflecting increased volumes from higher residential and commercial sales volumes due to customer growth.

Industrial Sales and Transportation

The primary changes that impacted volumes and margins from industrial sales and transportation services for the three months ended March 31, 2012 compared to March 31, 2011 were as follows:

- gas deliveries to industrials were up about 4 percent in the quarter over 2011 results. The volume increase in the period reflects a slight improvement in the economy. Specifically, we've added a few new customers in the forest products segment, and because of the price advantage of natural gas over oil we are beginning to see asphalt plants and other businesses converting to gas that we believe will be coming online in the second and third quarters; and
- margin from industrial customers was flat compared to last year, with increases in usage and margins from the manufacturing sector offset by margin losses from customers no longer in business or scaled back due to the weak economy.

Regulatory Adjustment for Income Taxes Paid

In prior years, Oregon law required the company to annually review the amount of income taxes collected in rates from utility operations and compare it to the amount of taxes the utility paid. In 2011, this law was repealed. We did not recognize any income or expense related to this regulatory adjustment for the three months ended March 31, 2012, but we did recognize margin revenues of $0.3 million in the three months ended March 31, 2011 for accrued interest attributed to regulatory surcharges related to the 2009 and 2010 tax years. For more information on regulatory income taxes paid, see Results of Operations – Business Segments – Utility Operations – Regulatory Adjustment for Income Taxes Paid in our 2011 Form 10-K.

Other Revenues

Other revenues include miscellaneous fee income and other regulatory adjustments. Other revenues increased from $0.6 million for the three months ended March 31, 2011 to $1.4 million for the three months ended March 31, 2012. The majority of this difference is related to the charge taken related to the earnings test, which was $1.0 million in the first quarter of 2011 and $0.4 million in the first quarter of 2012.

Cost of Gas Sold

Cost of gas sold as reported by the utility includes gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, production from gas reserves, and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the same costs are incurred, or expected to be incurred, by the utility. Customer rates are set each year so that if cost estimates were met we would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism whereby we either increase or decrease margin results based on a percentage of actual gas costs as compared to embedded gas costs in the PGA. Under this provision, our net income can be affected by differences between actual and expected gas costs, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases (see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). In addition, we recently entered into a regulatory agreement where we receive a rate base return on our investment in gas reserves (see Part II, Item 7., "Regulatory Matters-Rate Mechanisms-Purchased Gas Adjustment and Regulatory Matters-Rate Mechanisms-Gas Reserves in the 2011 Form 10-K). We use natural gas commodity-based hedge contracts (derivatives), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage our exposure to rising gas prices. Gains and losses from these financial hedge contracts are generally included in our PGA prices and normally do not impact net income because the hedged prices are reflected in our annual rate changes, subject to a regulatory prudency review. However, hedge contracts entered into after the annual PGA rates are set in Oregon can impact net income because we would be required to share in any gains or losses as compared to the corresponding commodity prices built into rates in the PGA. In Washington, 100 percent of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates (see Part II, Item 7., "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," and "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," in the 2011 Form 10-K, and Note 12 in this report). The following summarizes the major factors that contributed to changes in cost of gas sold for the three months ended March 31, 2012:

- total cost of gas sold decreased $10.9 million, or 6 percent, due to a 7 percent decrease in the average cost of gas sold per therm offset by a 2 percent increase in sales volumes and;
- the average gas cost collected through rates decreased from 60 cents per therm in the first quarter of 2011 to 56 cents per therm in the first quarter of 2012, primarily reflecting lower gas prices, which were passed on through PGA rate decreases effective November 1, 2011; and
- hedge losses totaling $29.4 million were realized and included in cost of gas sold for the three months ended March 31, 2012, compared to $20.9 million of hedge losses in the same period of 2011. Since the underlying hedge prices were included in our PGA billing rates, these losses did not impact margin or net income.

The amount recorded to pre-tax income from the shareholders' portion of our gas cost incentive sharing mechanism was a margin contribution of $2.6 million in the three months ended March 31, 2012 compared to $1.0 million in 2011. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our ownership interest in the Gill Ranch underground storage facility in California. For the three months ended March 31, 2012, our gas storage segment earned $0.8 million, or 3 cents per share, compared to $0.7 million, or 3 cents per share, for the same period in 2011. The increase in net income was primarily due to improvement in net operating losses at Gill Ranch, which had comparatively low storage revenues during the first quarter of 2011 because most of its capacity contracts did not begin until April 1, 2011. The Gill Ranch improvement was partially offset by lower revenues and net income from firm storage and asset management services at Mist. In total, gas storage margin increased $1.4 million to $6.7 million for the three months ended March 31, 2012.

Business Segments - Other

Our other business segment consists primarily of NNG Financial's investment in KB Pipeline, our equity investment in PGH, which in turn has invested in the Palomar pipeline project, and other miscellaneous non-utility investments and business activities. NNG Financial had total assets of $1.0 million and $1.1 million as of March 31, 2012 and 2011, respectively, primarily reflecting a non-controlling interest in KB Pipeline which is contracted to serve our utility. Our net equity investment in PGH as of March 31, 2012 and 2011 was $13.5 million and $14.8 million, respectively, with the decrease year-over-year reflecting a $1.3 million write-down taken in 2011. In aggregate, earnings from our other business segment for the three months ended March 31, 2012 and 2011 were net income of $10 thousand and a net loss of less than $100 thousand respectively. See Note 4 and Note 12 in the 2011 Form 10-K, and Note 4 and Note 11 in this report, for further details on our other segment and our investment in PGH.

Consolidated Operations

Operations and Maintenance

Consolidated operations and maintenance expense was $34.4 million in 2012, compared to $31.2 million in 2011, an increase of $3.2 million or 10 percent. The following summarizes the major factors that contributed to changes in operations and maintenance expense for the three months ended March 31, 2012 compared to March 31, 2011:

- a $1.1 million increase in utility payroll primarily related to an increase in field service employees;
- a $1.5 million increase in utility non-payroll expense including higher costs for new employee training, the Oregon general rate case, IT systems maintenance and other customer service costs; and
- a $0.9 million increase in utility employee benefit expense, principally related to heath care and pension costs. See below for an additional discussion on pension costs.

Partially offsetting the factors above was:

- a $0.3 million reduction in operating expense at Gill Ranch due to higher start-up costs for Gill Ranch in the first quarter of 2011.

Our bad debt expense as a percent of revenues was 0.23 percent for the twelve months ended March 31, 2012, compared to 0.18 percent for the same period last year. Our bad debt expense results over the past few years have been favorable despite challenging economic conditions. We believe credit risks are still elevated due to the continuing weak economy and high unemployment rates, but we expect our bad debt expense ratio over the long term to remain below 0.5 percent of revenues.

Our accounting expense for pension costs increased fairly significantly in 2012 largely due to lower interest rates; however, the OPUC approved the deferral of NW Natural's utility pension costs when its qualified defined benefit pension plans' operations and maintenance cost exceeds the amount currently recovered in rates. The pension cost deferral was recorded to a regulatory balancing account, which reduced operations and maintenance expense by $2.1 million for the three months ended March 31, 2012 and $1.3 million for the same period last year (see Note 8). Therefore, increased pension costs had a minimal effect on operations and maintenance expense, with the increase principally related to the cost allocation to our Washington customers. For further explanation of the pension balancing account, see "Regulatory Matters—Rate Mechanisms—Pension Deferral," above.

General Taxes

General taxes increased $0.7 million in the first three months of 2012 compared to 2011 primarily due to a $0.5 increase in property taxes at Gill Ranch because of capital investments added to our California tax base in 2011.

Depreciation and Amortization

For the three months ended March 31, 2012, depreciation and amortization expense increased by $0.6 million, or 4 percent compared to the same period in 2011. The increased expense in 2012 was related to higher depreciation at the utility and Gill Ranch because of plant asset additions.

Other Income and Expense – Net

The following table provides details on other income and expense – net by primary components:

	Three Months Ended March 31,	
Thousands	2012	2011
Gains from company-owned life insurance	$ 784	$ 505
Interest income	16	7
Income (loss) from equity investments	(1)	-
Net interest on deferred regulatory accounts	1,005	1,514
Gain (loss) on sale of investments	-	(96)
Other non-operating	(799)	(716)
Total other income and expense - net	$ 1,005	$ 1,214

Other income and expense – net for the three months ended March 31, 2012 decreased $0.2 million over 2011, with the decrease primarily due to lower interest from net regulatory asset account balances, partially offset by a $0.3 million increase in gains from life insurance policy proceeds.

Interest Expense – Net

Interest expense – net increased by $0.7 million for the three months ended March 31, 2012 compared to the first three months of 2011, with the increase primarily due to interest on Gill Ranch's new $40 million debt balance that was issued in late 2011.

Income Tax Expense

The change in income tax expense was not material for the three months ended March 31, 2012, compared to the same period in 2011. For more information on our income taxes, including a reconciliation between the statutory federal and state income tax rates and our effective rates, see Note 9.

Financial Condition

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt redemptions and short-term commercial paper maturities (see "Liquidity and Capital Resources," below, and Note 7). Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure at March 31, 2012 and 2011 and at December 31, 2011 was as follows:

	March 31,		December 31,
	2012	2011	2011
Common stock equity	49.7%	47.9%	46.5%
Long-term debt	42.7%	36.5%	41.7%
Short-term debt, including current maturities of long-term debt	7.6%	15.6%	11.8%
Total	100%	100%	100%

Liquidity and Capital Resources

At March 31, 2012, we had $4.0 million of cash and cash equivalents compared to $3.5 million at March 31, 2011. We also had $4.0 million in restricted cash at Gill Ranch as of March 31, 2012, which is being held as collateral on the long-term debt outstanding. The $0.9 million of restricted cash at Gill Ranch as of March 31, 2011 was held as collateral for equipment purchase contracts, but that amount was released back to Gill Ranch when contract conditions were met. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances, add short-term borrowing capacity, or pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC, and our use of proceeds from utility specific issuances are restricted to certain utility purposes. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, borrowings from multi-year credit facilities, cash available from surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use utility long-term debt proceeds to finance utility capital expenditures, refinance maturing debt of the utility and provide for general corporate purposes of the utility.

Capital markets over the past few years, including the commercial paper market, experienced significant volatility and tight credit conditions, but current conditions have improved significantly as reflected by tighter credit spreads and increased access to new financing for investment grade issuers. Based on our current debt ratings (see "Credit Ratings," below), we have been able to issue commercial paper and first mortgage bonds at attractive rates and have not needed to borrow from our back-up credit facilities. In the event that we are not able to issue new debt due to market conditions, we expect that our near term liquidity needs can be met by using cash balances or, for the utility segment, drawing upon our committed credit facilities. We also have a universal shelf registration filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and certain regulatory approvals. As of March 31, 2012, we have OPUC approval to issue up to $125 million of additional debt under the existing shelf registration for approved purposes.

In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional cash requirements and may trigger significant increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on March 31, 2012, we could have been required to post up to $40.4 million of collateral to our counterparties, but that assumes our long-term debt ratings were downgraded to non-investment grade levels, which would be a very significant change from current rating levels for NW Natural (see Note 12 and "Credit Ratings," below).

Additionally, in July 2010, the U.S. Congress passed and President Obama signed into law the "Wall Street Reform and Consumer Protection Act." The legislation requires additional government regulation of derivative and over-the-counter transactions, and could expand collateral requirements. While we continue to evaluate the legislation to determine its impact, if any, on our hedging procedures, results of operations, financial position and liquidity, we do not expect to know the full impact of the legislation until final regulations implementing the legislation are issued.

Recent developments that may have a significant impact on our liquidity and capital resources include pension contribution requirements, tax benefits and liabilities, environmental expenditures and insurance recoveries, and refunds to customers. With respect to pension requirements, we expect to make significant contributions over the next several years until we are fully funded under the Pension Protection Act rules (see "Pension Cost and Funding Status of Qualified Retirement Plans," below). With respect to federal income tax liabilities, an extension was granted that allowed us to take 100 percent bonus depreciation on qualified expenditures during 2011, and allows 50 percent bonus depreciation on a majority of our capital expenditures in 2012, which significantly reduces our tax liability for those tax years and provides cash flow benefits in 2012 and 2013 (see "Cash Flows—Operating Activities," below). With respect to environmental liabilities, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through insurance or utility rates over the next several years, although the amount and timing of these expenditures and recoveries is uncertain (see Note 13).

With respect to customer refunds or credits, our actual gas costs have been significantly lower in recent months than the gas prices embedded in customer rates. As a result, our PGA incentive sharing mechanism deferred 90 percent of these gas cost savings attributed to Oregon, and 100 percent of the savings attributed to Washington, into a regulatory account for refund back to customers (see "Purchased Gas Adjustment," above). Ordinarily, these refunds would be credited to customer rates in the next year's PGA filing, but in April 2012 the company requested regulatory approval to immediately credit an estimated $35 million to Oregon customers and $4 million to Washington customers through billing credits. In addition, in April 2012 the company also requested regulatory approval to provide its Oregon utility customers with an estimated $9 million interstate storage credit from our regulatory incentive sharing mechanism related to gas storage and asset management services. If approved, we intend to apply both of these credits to customer bills in June of 2012.

Our storage segment's short-term liquidity is supported by cash balances, internal cash flow from operations, external financing, and to a certain extent on funding from its parent company. Gill Ranch has a limited operational history, having begun operations in October 2010. Although we anticipate operating cash flows to be sufficient for liquidity purposes, the amount and timing of these cash flows are uncertain. In November 2011, Gill Ranch issued $40 million of senior secured notes, with a fixed interest rate on $20 million and a variable interest rate on the remaining $20 million. The average combined interest rate on the notes was 7.38 percent per annum through March 31, 2012. These notes are secured by all of the membership interests in Gill Ranch Storage, LLC, and are nonrecourse to NW Natural and other entities of the consolidated group. The maturity date of these notes is November 30, 2016.

Under the note agreements, Gill Ranch is subject to certain covenants and restrictions, including but not limited to a financial covenant that requires Gill Ranch to maintain minimum adjusted EBITDA at various levels over the term of the notes. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the agreements, Gill Ranch is also subject to a debt service reserve requirement of 10 percent of the outstanding principal amount, initially $4 million, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on incurrence of additional debt.

Based on several factors, including our current credit ratings, our commercial paper program, current cash reserves, committed credit facilities, and our expected ability to issue long-term debt under our universal shelf registration, we believe our liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations and investing and financing activities discussed below.

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas inventories and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities (see “Credit Agreements,” below). Our commercial paper program did not experience any liquidity disruptions as a result of the credit problems that affected issuers of asset-backed commercial paper and certain other commercial paper programs over the last several years. At March 31, 2012 and 2011, our utility had commercial paper outstanding of $113.7 million and $186.4 million, respectively. The effective interest rate on the utility’s commercial paper outstanding at March 31, 2012 and 2011 was 0.2 percent and 0.4 percent, respectively.

Credit Agreements

We have a syndicated multi-year credit agreement for unsecured revolving loans totaling $250 million. The original term of this credit agreement was extended through May 31, 2013. All lenders under our syndicated agreement are major financial institutions with committed balances and investment grade credit ratings as of March 31, 2012 (see table below). This credit facility is scheduled to expire next year, and we plan to negotiate a replacement credit facility later this year.

	Loan Commitment (In Thousands)	
Lender rating, by category	Syndicated Facility	
AAA/Aaa	$	-
AA/Aa		165,000
A/A		85,000
BBB/Baa		-
Total	$	250,000

Based on credit market conditions, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders’ creditworthiness, including a review of capital ratios, credit default swap spreads and credit ratings, we believe the risk of lender default is minimal.

As discussed above, we extended commitments with all of our lenders under the $250 million syndicated agreement through May 31, 2013. This syndicated agreement allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million. This syndicated agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment.

Any principal and unpaid interest amounts owed on borrowings under the credit agreements are due and payable on or before the maturity date. There were no outstanding balances under these credit agreements at March 31, 2012 and 2011. These agreements require us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at March 31, 2012 and 2011, with consolidated indebtedness to total capitalization ratios of 50 percent and 52 percent, respectively.

The syndicated agreement also requires that we maintain credit ratings with S&P and Moody's and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings by S&P or by Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. However, a change in our debt rating below BBB- by S&P or Baa3 by Moody's would require additional approval from the OPUC prior to issuance of utility debt, and interest rates on any loans outstanding under the credit agreements are tied to debt ratings, which would increase or decrease the cost of any loans under the credit agreements when ratings are changed (see "Credit Ratings," below).

Credit Ratings

Our debt credit ratings are a factor in our liquidity, affecting our access to the capital markets, including the commercial paper market. Our debt credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. A change in our ratings below BBB- by S&P or Baa3 by Moody's would require additional approval from the OPUC prior to our issuing additional long-term debt.

The following table summarizes our current debt ratings from S&P and Moody's:

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-1
Senior secured (long-term debt)	A+	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Stable

The above credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Maturities and Redemptions of Long-Term Debt

For the three months ended March 31, 2012, $40 million of secured Medium Term Notes (MTNs) with a coupon rate of 7.13% were redeemed at maturity. Over the next twelve months, there are no scheduled redemptions of long-term debt. For long-term debt maturing over the next five years, see "Contractual Obligations" in our 2011 Form 10-K.

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are affected by net income, working capital requirements, and other cash and non-cash adjustments to operating results. For the three months ended March 31, 2012, cash flows from operating activities totaled $114.1 million, compared to $108.1 million in 2011. The significant factors contributing to changes in operating cash flows in the first quarter of 2012 compared to 2011 are as follows:

- an increase of $ 23.5 million from deferred gas cost savings, which reflects a higher level of refunds due utility customers for differences between actual gas prices and the embedded gas prices in amounts billed to customers;
- an increase of $9.5 million from changes in customer receivables primarily due to higher account balances at the end of 2011 compared to 2010 because of colder weather at the end of 2011;

- a decrease of $14.2 million from changes in gas inventories primarily due to lower inventory withdrawals during the first quarter of 2012 as compared to 2011 because the utility was able to take advantage of lower spot gas prices to reduce cost of gas;
- a decrease of $11.8 million from changes in income tax account balances primarily related to prior year income tax refunds received in the first quarter of 2011; and
- a decrease of $11.6 million from changes in gas costs payable primarily due to weather and inventory withdrawal impacts on gas purchases between the two periods.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the Tax Relief Act) allowed 100 percent bonus depreciation on qualified property placed in service between September 9, 2010 through December 31, 2011. It also extended the 50 percent bonus depreciation deduction to qualifying property placed in service during 2012. As a result of this and prior legislation allowing bonus depreciation, we generated cash flow benefits of $27.0 million and $25.0 million for the three months ended March 31, 2012 and 2011, respectively. These and other tax benefits resulted in a net operating tax loss for 2010, which was carried back to the tax year 2009 and resulted in a federal income tax refund of $22.3 million received in 2011. We also continue to recognize an increase in cash flows for reduced current tax liabilities due to net operating loss (NOL) carry-forwards. As of March 31, 2012, we had an income tax receivable balance of $1.7 million, which we expect to realize during 2012, and an NOL carry-forward balance of $57.0 million. We anticipate being able to use the full amount of the current NOL carry-forward balance in future years. The federal NOL from 2010 would expire in 2031 if not used in earlier years.

Also affecting cash flow from operating activities is the amount of cash contributions being made to the utility's qualified defined benefit pension plans (qualified DB plans). During the first quarter of 2012, we contributed $13.8 million to the qualified DB plans, which was significantly higher than the $2.0 million in non-cash expense recognized on the income statement, and for the first quarter of 2011, we contributed $13.6 million while only $1.8 million in non-cash expense was recognized on the income statement. We expect contributions to the qualified DB plans to exceed non-cash expense for the next few years, but amounts and timing of these expenses will depend on market interest rates and investment returns on the plans' assets.

Investing Activities

Cash used in investing activities for the three months ended March 31, 2012 totaled $37.7 million, up from $25.5 million for the same period in 2011. The increase in investing activities is primarily due to a $17.2 million investment in utility gas reserves during the first quarter of 2012 (see "Executive Summary – Strategic Opportunities – Gas Reserves" above for a discussion of our gas reserve agreement with Encana). Utility capital expenditures were $18.9 million and gas storage capital spend was $1.5 million in the three months ended March 31, 2012, as compared to $16.7 million and $8.7 million, respectively, for the same period in 2011.

In the first quarter of 2012, we purchased a property in Sherwood, Oregon which, along with anticipated sale of existing properties, will enable us to consolidate certain operations at the new location. This will allow us to consolidate and streamline certain field operations and maintenance groups, plus provide us with expanded scenario-based pipeline training capabilities and a back-up business operations site.

Over the five-year period 2012 through 2016, total utility capital expenditures are estimated to be between $400 and $500 million and utility expenditures for gas reserves are estimated to be $200 million. The estimated level of utility capital requirements over the next five years reflects assumptions on customer growth, storage development for the utility, technology investments and utility distribution system improvements, including requirements under current pipeline safety programs. New federal pipeline safety rules could increase our capital requirement estimates over the next five years. Most of the funds required to make these investments over the next five years are expected to be internally generated, and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing.

In 2012, we expect to spend less than $5 million on non-utility capital projects, including the storage businesses and Palomar. Non-utility gas storage capital expenditures in 2012 are expected to be paid primarily from working capital, and potentially with additional funds from the NW Natural consolidated group. Palomar expects to continue working on revised plans for the east pipeline segment, including plans to conduct an open season to re-evaluate regional needs. The initial planning and permitting costs have been financed with equity funds from NW Natural and our partner, TransCanada American Investments Ltd. For more information on non-utility investment opportunities, see Note 11 and “Strategic Opportunities—Gas Storage Development” and “—Pipeline Diversification,” above.

Financing Activities

Cash used in financing activities during the three months ended March 31, 2012 totaled $78.1 million, up from cash used of $82.5 million for the same period in 2011. The primary change in financing activity in 2012 over 2011 was the amount used to redeem $40 million of long-term debt in the first quarter of 2012, which reduced the amount of cash flow used to reduce the short-term debt balances outstanding from $71 million in 2011 to $27.9 million in 2012. We continue to use long-term debt proceeds to finance capital expenditures, refinance maturing short-term or long-term debt maturities, and for general corporate purposes. We anticipate issuing long-term debt later on during 2012.

Pension Cost and Funding Status of Qualified Retirement Plans

We make contributions to company-sponsored qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plans were underfunded by $146.9 million at December 31, 2011. For the three months ended March 31, 2012, we made cash contributions totaling $13.8 million into these qualified pension plans. We anticipate making additional contributions before year end, bringing the total amount to around $28 million in 2012. In 2011 and 2010, we contributed $20 million and $10 million, respectively, into the qualified defined benefit pension plans. For more information on the funded status of our qualified retirement plans and other postretirement benefits, see Note 8, and Part II, Item 7., “Financial Condition—Pension Cost and Funding Status of Qualified Retirement Plans,” and Part II, Item 8., Note 9, “Pension and Other Postretirement Benefits,” in the 2011 Form 10-K.

We also contribute to a multi-employer union pension plan (Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling $0.1 million to the Western States Plan in both the three months ended March 31, 2012 and 2011, and we expect to contribute a total of $0.4 million during 2012. See Note 8 for further discussion.

Ratios of Earnings to Fixed Charges

For the three and twelve months ended March 31, 2012 and the twelve months ended December 31, 2011, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 6.81, 3.36 and 3.41 respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. See Exhibit 12.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies (see Part II, Item 7., “Application of Critical Accounting Policies and Estimates,” in our 2011 Form 10-K). At March 31, 2012, we had a regulatory asset of $112.3 million for deferred environmental costs, which includes $75.1 million for additional costs expected to be paid in the future and accrued interest of $20.4 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 13.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price and storage value risk, interest rate risk, foreign currency risk, credit risk, and weather risk. We monitor and manage these financial exposures as an integral part of our overall risk management program. No material changes have occurred related to our disclosures about market risk for the three months ended March 31, 2012. See Part I, Item 1A., "Risk Factors," and Part II, Item 7A. "Quantitative and Qualitative Disclosures about Market Risk," in the 2011 Form 10-K and Part II, Item 1A., "Risk Factors," in this report for details regarding these risks.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The Company's management, together with its consolidated subsidiaries, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended March 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 13 and those proceedings disclosed and incorporated by reference in Part I, Item 3., “Legal Proceedings,” in our 2011 Form 10-K, we have only routine nonmaterial litigation in the ordinary course of business.

ITEM 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, “Item 1A. Risk Factors,” in our 2011 Form 10-K. In addition to the other information set forth in this report, you should carefully consider those risk factors, which could materially affect our business, financial condition or results of operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table provides information about purchases by us during the quarter ended March 31, 2012 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASE OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased(1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(2)	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(2)
Balance forward			2,124,528	$ 16,732,648
01/01/12 - 01/31/12	-	$ -	-	-
02/01/12 - 02/29/12	1,062	47.66	-	-
03/01/12 - 03/31/12	7,888	46.14	-	-
Total	8,950	$ 46.32	2,124,528	$ 16,732,648

(1) During the quarter ended March 31, 2012, 8,950 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended March 31, 2012, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2012 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended March 31, 2012, no shares of our common stock were purchased pursuant to this program. Since the program’s inception in 2000 we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

ITEM 6. EXHIBITS

See Exhibit Index attached hereto.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NORTHWEST NATURAL GAS COMPANY
(Registrant)

Dated: May 4, 2012

/s/ Stephen P. Feltz
Stephen P. Feltz
Principal Accounting Officer
Treasurer and Controller

NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX
To
Quarterly Report on Form 10-Q
For the Quarter Ended
March 31, 2012

Exhibit Number	Document
12	Statement re computation of ratios of earnings to fixed charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	*The following materials from Northwest Natural Gas Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.

* In accordance with Rule 406T of Regulation S-T, the XBRL-related information in Exhibit 101 to this Quarterly Report on Form 10-Q is deemed not filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act, is deemed not filed for purposes of Section 18 of the Exchange Act and otherwise is not subject to liability under these sections.

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Section 2: EX-12 (EXHIBIT 12 FIXED CHARGES)

EXHIBIT 12

NORTHWEST NATURAL GAS COMPANY
Ratio of Earnings to Fixed Charges
Thousands, except per share amount
(Unaudited)

	Year Ended December 31, 2011	2010	2009	2008	2007	12 Months Ended March 31, 2012	Three months(1) Ended March 31, 2012
Fixed Charges, as defined:							
Interest on Long-Term Debt	$ 37,515	$ 39,198	$ 37,447	$ 33,605	$ 34,294	$ 38,486	$ 10,252
Other Interest	2,976	1,587	1,937	4,022	4,116	3,062	534
Amortization of Debt Discount and Expense	1,729	1,766	1,503	700	711	1,768	467
Interest Portion of Rentals	2,213	2,130	1,735	1,551	1,523	2,129	536
Total Fixed Charges, as defined	$ 44,433	$ 44,681	$ 42,622	$ 39,878	$ 40,644	$ 45,445	$ 11,789
Earnings, as defined:							
Net Income	$ 63,898	$ 72,667	$ 75,122	$ 69,525	$ 74,497	$ 63,732	$ 40,607
Taxes on Income	43,382	49,462	46,671	40,678	44,060	43,401	27,873
Fixed Charges, as above	44,433	44,681	42,622	39,878	40,644	45,445	11,789
Total Earnings, as defined	$ 151,713	$ 166,810	$ 164,415	$ 150,081	$ 159,201	$ 152,578	$ 80,269
Ratio of Earnings to Fixed Charges	3.41	3.73	3.86	3.76	3.92	3.36	6.81

(1)A significant part of the business of NW Natural is of a seasonal nature; therefore, the ratios of earnings to fixed charges for the interim periods are not necessarily indicative of the results for a full year.

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Section 3: EX-31.1 (CEO CERTIFICATION)

EXHIBIT 31.1

CERTIFICATION

I, Gregg S. Kantor, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarterly period ended March 31, 2012 of Northwest Natural Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2012

/s/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer

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Section 4: EX-31.2 (CFO CERTIFICATION)

EXHIBIT 31.2

CERTIFICATION

I, David H. Anderson, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarterly period ended March 31, 2012 of Northwest Natural Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2012

/s/ David H. Anderson
David H. Anderson
Senior Vice President and Chief Financial Officer

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Section 5: EX-32.1 (CEO AND CFO CERTIFICATION)

EXHIBIT 32.1

NORTHWEST NATURAL GAS COMPANY
Certificate Pursuant to Section 906
of Sarbanes – Oxley Act of 2002

Each of the undersigned, GREGG S. KANTOR, the President and Chief Executive Officer, and DAVID H. ANDERSON, the Senior Vice President and Chief Financial Officer, of NORTHWEST NATURAL GAS COMPANY (the Company), DOES HEREBY CERTIFY that:

1. The Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 (the Report) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has caused this instrument to be executed this 4th day of May 2012.

/s/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer

/s/ David H. Anderson
David H. Anderson
Senior Vice President and
Chief Financial Officer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Northwest Natural Gas Company and will be retained by Northwest Natural Gas Company and furnished to the Securities and Exchange Commission or its staff upon request.

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PIEDMONT NATURAL GAS CO INC (PNY)

10-Q

Quarterly report pursuant to sections 13 or 15(d)
Filed on 03/09/2012
Filed Period 01/31/2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended January 31, 2012

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________________ to ____________________

Commission File Number 1-6196

Piedmont Natural Gas Company, Inc.

(Exact name of registrant as specified in its charter)

North Carolina	56-0556998
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
4720 Piedmont Row Drive, Charlotte, North Carolina	28210
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (704) 364-3120

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☑ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☑ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☑ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at March 1, 2012
Common Stock, no par value	71,685,958

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Piedmont Natural Gas Company, Inc.

Form 10-Q

for

January 31, 2012

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Part I. Financial Information

Item 1. Financial Statements

Piedmont Natural Gas Company, Inc. and Subsidiaries
Consolidated Balance Sheets (Unaudited)
(In thousands)

	January 31, 2012	October 31, 2011
ASSETS		
Utility Plant:		
Utility plant in service	$ 3,405,811	$ 3,377,310
Less accumulated depreciation	992,867	974,631
Utility plant in service, net	2,412,944	2,402,679
Construction work in progress	277,710	217,832
Plant held for future use	6,751	6,751
Total utility plant, net	2,697,405	2,627,262
Other Physical Property, at cost (net of accumulated depreciation of $815 in 2012 and $806 in 2011)	443	452
Current Assets:		
Cash and cash equivalents	10,106	6,777
Trade accounts receivable (less allowance for doubtful accounts of $2,755 in 2012 and $1,347 in 2011)	159,278	57,035
Income taxes receivable	29,216	15,966
Other receivables	1,336	2,547
Unbilled utility revenues	82,696	28,715
Inventories:		
Gas in storage	105,308	91,124
Materials, supplies and merchandise	1,275	1,368
Gas purchase derivative assets, at fair value	1,776	2,772
Amounts due from customers	34,219	38,649
Prepayments	4,784	39,128
Deferred income taxes	—	1,793
Other current assets	257	147
Total current assets	430,251	286,021
Noncurrent Assets:		
Equity method investments in non-utility activities	91,626	85,121
Goodwill	48,852	48,852
Marketable securities, at fair value	2,078	1,439
Overfunded postretirement asset	22,879	22,879
Regulatory asset for postretirement benefits	80,049	81,073
Unamortized debt expense	11,098	11,315
Regulatory cost of removal asset	19,776	19,336
Other noncurrent assets	59,714	58,791
Total noncurrent assets	336,072	328,806
Total	$ 3,464,171	$ 3,242,541

See notes to consolidated financial statements.

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Piedmont Natural Gas Company, Inc. and Subsidiaries
Consolidated Balance Sheets (Unaudited)
(In thousands)

	January 31, 2012	October 31, 2011
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Stockholders' equity:		
Cumulative preferred stock — no par value — 175 shares authorized	$ —	$ —
Common stock — no par value — shares authorized: 200,000; shares outstanding: 71,674 in 2012 and 72,318 in 2011	424,689	446,791
Retained earnings	605,859	550,584
Accumulated other comprehensive loss	(462)	(452)
Total stockholders' equity	1,030,086	996,923
Long-term debt	675,000	675,000
Total capitalization	1,705,086	1,671,923
Current Liabilities:		
Bank debt	457,500	331,000
Trade accounts payable	104,425	85,721
Other accounts payable	30,886	43,959
Accrued interest	11,139	20,038
Customers' deposits	26,101	25,462
Deferred income taxes	35,096	—
General taxes accrued	3,779	21,262
Amounts due to customers	8,615	2,617
Other current liabilities	14,431	4,073
Total current liabilities	691,972	534,132
Noncurrent Liabilities:		
Deferred income taxes	537,041	512,961
Unamortized federal investment tax credits	1,915	2,004
Accumulated provision for postretirement benefits	14,685	14,671
Cost of removal obligations	473,086	466,000
Other noncurrent liabilities	40,386	40,850
Total noncurrent liabilities	1,067,113	1,036,486
Commitments and Contingencies (Note 8)		
Total	$ 3,464,171	$ 3,242,541

See notes to consolidated financial statements.

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Piedmont Natural Gas Company, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Unaudited)
(In thousands except per share amounts)

	Three Months Ended January 31	
	2012	2011
Operating Revenues	$471,840	$652,056
Cost of Gas	251,603	422,050
Margin	220,237	230,006
Operating Expenses:		
Operations and maintenance	58,397	51,058
Depreciation	26,178	25,047
General taxes	8,622	11,097
Utility income taxes	47,221	51,935
Total operating expenses	140,418	139,137
Operating Income	79,819	90,869
Other Income (Expense):		
Income from equity method investments	6,292	7,756
Non-operating income	61	168
Non-operating expense	(421)	(384)
Income taxes	(2,318)	(2,952)
Total other income (expense)	3,614	4,588
Utility Interest Charges:		
Interest on long-term debt	10,023	12,099
Allowance for borrowed funds used during construction	(4,423)	(2,334)
Other	1,606	1,252
Total utility interest charges	7,206	11,017
Net Income	76,227	84,440
Other Comprehensive Income (Loss), net of tax:		
Unrealized gain (loss) from hedging activities of equity method investments, net of tax of ($278) in 2012 and $121 in 2011	(436)	185
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of $272 in 2012 and $252 in 2011	426	393
Total other comprehensive income (loss)	(10)	578
Comprehensive Income	$ 76,217	$ 85,018
Average Shares of Common Stock:		
Basic	72,126	72,194
Diluted	72,433	72,514
Earnings Per Share of Common Stock:		
Basic	$ 1.06	$ 1.17
Diluted	$ 1.05	$ 1.16
Cash Dividends Per Share of Common Stock	$ 0.29	$ 0.28

See notes to consolidated financial statements.

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Piedmont Natural Gas Company, Inc. and Subsidiaries
Consolidated Statements of Cash Flows (Unaudited)
(In thousands)

	Three Months Ended January 31	
	2012	2011
Cash Flows from Operating Activities:		
Net income	$ 76,227	$ 84,440
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	27,257	25,975
Amortization of investment tax credits	(89)	(93)
Allowance for doubtful accounts	1,408	2,447
Income from equity method investments	(6,292)	(7,756)
Distributions of earnings from equity method investments	1,600	793
Deferred income taxes, net	60,974	35,081
Changes in assets and liabilities:		
Gas purchase derivatives, at fair value	996	(533)
Receivables	(156,455)	(276,564)
Inventories	(14,091)	3,459
Amounts due from/to customers	10,428	63,361
Settlement of legal asset retirement obligations	(221)	(329)
Overfunded postretirement asset	—	(22,225)
Regulatory asset for postretirement benefits	1,024	407
Other assets	20,414	45,621
Accounts payable	17,164	68,339
Provision for postretirement benefits	14	246
Other liabilities	(15,711)	(1,428)
Net cash provided by operating activities	24,647	21,241
Cash Flows from Investing Activities:		
Utility construction expenditures	(98,140)	(38,168)
Allowance for funds used during construction	(4,423)	(2,334)
Contributions to equity method investments	(1,828)	(1,591)
Distributions of capital from equity method investments	—	748
Proceeds from sale of property	211	464
Investments in marketable securities	(677)	(426)
Other	251	907
Net cash used in investing activities	(104,606)	(40,400)

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Piedmont Natural Gas Company, Inc. and Subsidiaries
Consolidated Statements of Cash Flows (Unaudited)
(In thousands)

	Three Months Ended January 31	
	2012	2011
Cash Flows from Financing Activities:		
Borrowings under bank debt	$ 282,000	$ 721,500
Repayments under bank debt	(155,500)	(648,000)
Retirement of long-term debt	—	(18)
Expenses related to issuance of debt	(131)	(2,152)
Issuance of common stock through dividend reinvestment and employee stock plans	4,914	4,811
Repurchases of common stock	(27,016)	(22,232)
Dividends paid	(20,979)	(20,278)
Net cash provided by financing activities	83,288	33,631
Net Increase in Cash and Cash Equivalents	3,329	14,472
Cash and Cash Equivalents at Beginning of Period	6,777	5,619
Cash and Cash Equivalents at End of Period	$ 10,106	$ 20,091
Cash Paid During the Year for:		
Interest	$ 20,604	$ 21,142
Income Taxes:		
Income taxes paid	$ 1,981	$ 999
Income taxes refunded	—	—
Income taxes, net	$ 1,981	$ 999
Noncash Investing and Financing Activities:		
Accrued construction expenditures	$ 11,643	$ 4,382

See notes to consolidated financial statements.

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Piedmont Natural Gas Company, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity (Unaudited)
(In thousands except per share amounts)

	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, October 31, 2010	72,282	$ 445,640	$ 519,831	$ (530)	$ 964,941
Comprehensive Income:					
Net income			84,440		84,440
Other comprehensive income				578	578
Total comprehensive income					85,018
Common Stock Issued	284	8,041			8,041
Common Stock Repurchased	(800)	(22,232)			(22,232)
Tax Benefit from Dividends Paid on ESOP Shares			24		24
Dividends Declared ($.28 per share)			(20,278)		(20,278)
Balance, January 31, 2011	71,766	$ 431,449	$ 584,017	$ 48	$ 1,015,514
Balance, October 31, 2011	72,318	$ 446,791	$ 550,584	$ (452)	$ 996,923
Comprehensive Income:					
Net income			76,227		76,227
Other comprehensive loss				(10)	(10)
Total comprehensive income					76,217
Common Stock Issued	156	4,914			4,914
Common Stock Repurchased	(800)	(27,016)			(27,016)
Tax Benefit from Dividends Paid on ESOP Shares			27		27
Dividends Declared ($.29 per share)			(20,979)		(20,979)
Balance, January 31, 2012	71,674	$ 424,689	$ 605,859	$ (462)	$ 1,030,086

See notes to consolidated financial statements.

Piedmont Natural Gas Company, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)

1. Summary of Significant Accounting Policies

Unaudited Interim Financial Information

The consolidated financial statements have not been audited. We have prepared the unaudited consolidated financial statements under the rules of the Securities and Exchange Commission (SEC). Therefore, certain financial information and note disclosures normally included in annual financial statements prepared in conformity with generally accepted accounting principles (GAAP) in the United States of America are omitted in this interim report under these SEC rules and regulations. These financial statements should be read in conjunction with the Consolidated Financial Statements and Notes included in our Form 10-K for the year ended October 31, 2011.

Seasonality and Use of Estimates

The unaudited consolidated financial statements include all normal recurring adjustments necessary for a fair statement of financial position at January 31, 2012 and October 31, 2011, the results of operations for the three months ended January 31, 2012 and 2011, and cash flows for the three months ended January 31, 2012 and 2011. Our business is seasonal in nature. The results of operations for the three months ended January 31, 2012 do not necessarily reflect the results to be expected for the full year.

We make estimates and assumptions when preparing the consolidated financial statements. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

Significant Accounting Policies

Our accounting policies are described in Note 1 to the consolidated financial statements in our Form 10-K for the year ended October 31, 2011. There were no significant changes to those accounting policies during the three months ended January 31, 2012.

Rate-Regulated Basis of Accounting

Our utility operations are subject to regulation with respect to rates, service area, accounting and various other matters by the regulatory commissions in the states in which we operate. The accounting regulations provide that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. In applying these regulations, we capitalize certain costs and benefits as regulatory assets and liabilities, respectively, in order to provide for recovery from or refund to utility customers in future periods.

Our regulatory assets are recoverable through either base rates or rate riders specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period the rates are in effect. As such, all of our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that accounting for the effects of regulation were no longer applicable, we would recognize a write-off of the regulatory assets and regulatory liabilities that would result in an adjustment to net income. Our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate. It is our opinion that all regulatory assets are recoverable in current rates or future rate proceedings.

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Regulatory assets and liabilities in the consolidated balance sheets as of January 31, 2012 and October 31, 2011 are as follows.

In thousands	January 31, 2012	October 31, 2011
Regulatory assets	$ 195,315	$ 200,135
Regulatory liabilities	479,548	466,953

Inter-company transactions have been eliminated in consolidation where appropriate; however, we have not eliminated inter-company profit on sales to affiliates and costs from affiliates in accordance with accounting regulations prescribed under rate-based regulation. For information on related party transactions, see Note 11 to the consolidated financial statements in this Form 10-Q.

Fair Value Measurements

The carrying values of cash and cash equivalents, receivables, bank debt, accounts payable, accrued interest and other current liabilities approximate fair value as all amounts reported are to be collected or paid within one year. Our financial assets and liabilities are recorded at fair value. They consist primarily of derivatives that are recorded in the consolidated balance sheets in accordance with derivative accounting standards and marketable securities that are classified as trading securities and are held in a rabbi trust established for our deferred compensation plans.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit date. We utilize market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for fair value measurements and endeavor to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The fair value of our financial assets and liabilities are subject to potentially significant volatility based on changes in market prices, the portfolio valuation of our contracts, as well as the maturity and settlement of those contracts, and subsequent newly originated transactions, each of which directly affects the estimated fair value of our financial instruments. We are able to classify fair value balances based on the observance of those inputs in the fair value hierarchy levels as set forth in the fair value guidance.

For the fair value measurements of our derivatives and marketable securities, see Note 7 to the consolidated financial statements in this Form 10-Q. For the fair value measurements of our benefit plan assets, see Note 9 to our Form 10-K for the year ended October 31, 2011. For further information on our fair value methodologies, see "Fair Value Measurements" in Note 1 to the consolidated financial statements in our Form 10-K for the year ended October 31, 2011. There were no significant changes to these fair value methodologies during the three months ended January 31, 2012.

Recently Issued Accounting Guidance

In January 2010, the Financial Accounting Standards Board (FASB) issued accounting guidance to require separate disclosures about purchases, sales, issuances and settlements relating to Level 3 fair value measurements. The guidance was effective for interim periods for fiscal years beginning after December 15,

2010. We adopted the guidance for Level 3 disclosures for recurring and non-recurring items covered under the fair value guidance for the first quarter of our fiscal year ending October 31, 2012. Since the guidance addresses only disclosures related to fair value measurements under Level 3, the adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

In May 2011, the FASB issued accounting guidance to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and International Financial Reporting Standards (IFRS). The amendments are not intended to change the application of the current fair value requirements, but to clarify the application of existing requirements. The guidance does change particular principles or requirements for measuring fair value or disclosing information about fair value measurements. To improve consistency, language has been changed to ensure that U.S. GAAP and IFRS fair value measurement and disclosure requirements are described in the same way. The guidance will be effective for interim and annual periods beginning after December 15, 2011. We will adopt the amended fair value guidance for the second quarter of our fiscal year ending October 31, 2012. The adoption of this guidance will have no material impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued accounting guidance to increase the prominence of other comprehensive income (OCI) in financial statements. The guidance gives businesses two options for presenting OCI. An OCI statement can be included with the statement of income, and together the two will make a statement of comprehensive income. Alternatively, businesses can present a separate OCI statement, but that statement must appear consecutively with the statement of income within the financial report. This guidance, which we early adopted and presented in one continuous statement for the first quarter of our fiscal year ending October 31, 2012, is effective for interim and annual periods beginning after December 15, 2011. The adoption of this guidance had no impact on our financial position, results of operations or cash flows.

In December 2011, the FASB issued accounting guidance to improve disclosures and make information more comparable to IFRS regarding the nature of an entity's rights of setoff and related arrangements associated with its financial instruments and derivative instruments. The guidance requires the entity to disclose information about offsetting and related arrangements in tabular format to enable users of financial statements to understand the effect of those arrangements on the entity's financial position. The new disclosure requirements are effective for annual periods beginning after January 1, 2013 and interim periods therein and require retrospective application in all periods presented. We will adopt this offsetting disclosure guidance for the first quarter of our fiscal year ending October 31, 2014. The adoption of this guidance will have no impact on our financial position, results of operations or cash flows.

2. Regulatory Matters

On August 1, 2011, we filed testimony with the North Carolina Utilities Commission (NCUC) in support of our gas cost purchasing and accounting practices for the twelve months ended May 31, 2011. On January 25, 2012, the NCUC issued an order finding us prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery of our gas costs.

On August 30, 2011, we filed an annual report with the Tennessee Regulatory Authority (TRA) reflecting the shared gas cost savings from gains and losses derived from gas purchase benchmarking and secondary market transactions for the twelve months ended June 30, 2011 under the Tennessee Incentive Plan (TIP). We are unable to predict the outcome of this proceeding at this time.

On September 30, 2011, we filed an annual report for the twelve months ended June 30, 2011 with the TRA that reflected the transactions in the deferred gas cost account for the Actual Cost Adjustment mechanism. We are unable to predict the outcome of this proceeding at this time.

On September 2, 2011, we filed a general rate application with the TRA requesting authority for an increase to rates and charges for all customers to produce overall incremental revenues of $16.7 million annually, or 8.9% above the current annual revenues. In addition, the petition also requested modifications of the cost allocation and rate designs underlying our existing rates, including shifting more of our cost recovery to our fixed charges and away from the volumetric charges and expanding the period of the weather normalization adjustment to October through April. We also sought approval to implement a school-based energy education program with appropriate cost recovery mechanisms, amortization of certain regulatory assets and deferred accounts, revised depreciation rates for plant and changes to the existing service regulations and tariffs. The changes were proposed to be effective March 1, 2012. On December 22, 2011, we and the Consumer Advocate and Protection Division reached a stipulation and settlement agreement resolving all issues in this proceeding, including an increase in rates and charges to all customers effective March 1, 2012 designed to produce overall incremental revenues of $11.9 million annually, or 6.3% above the current annual revenue, based upon an approved rate of return on equity of 10.2%. The new cost allocations shift recovery of fixed charges from 29% to 37% with a resulting decrease of volumetric charges from 71% to 63%. The stipulation and settlement agreement did not include a cost recovery mechanism for a school-based energy education program. On January 23, 2012, a hearing on this matter was held by the TRA. The TRA approved the settlement agreement at the January 23, 2012 hearing.

On February 26, 2010, we filed a petition with the TRA to adjust the applicable rate for the collection of the Nashville franchise fee from certain customers. The proposed rate adjustment was calculated to recover the net $2.9 million of under-collected Nashville franchise fee payments as of May 31, 2009. In April 2010, the TRA passed a motion approving a new Nashville franchise fee rate designed to recover only the net under-collections that have accrued since June 1, 2005, which would deny recovery of $1.5 million for us. In October 2011, the TRA issued an order denying us the recovery of $1.5 million of franchise fees consistent with its April 2010 motion, and we recorded $1.5 million in operations and maintenance expenses. In November 2011, we filed for reconsideration, which was granted on November 21, 2011. On February 13, 2012, a hearing on this matter was held before the TRA. We are unable to predict the outcome of this proceeding at this time. However, we do not believe this matter will have a material effect on our financial position, results of operations or cash flows.

In October 2010, the TRA approved a petition requesting deferred accounting treatment for the direct incremental expenses incurred as a result of our response to severe flooding in Nashville in May 2010. We had deferred $1 million as of January 31, 2012 and October 31, 2011 related to the flooding. As a part of the rate case stipulation and settlement agreement mentioned above, the TRA approved the recovery of these deferred expenses to be amortized over 96 months beginning March 1, 2012.

3. Earnings per Share

We compute basic earnings per share (EPS) using the weighted average number of shares of common stock outstanding during each period. Shares of common stock to be issued under approved incentive compensation plans are contingently issuable shares and are included in our calculation of fully diluted earnings per share.

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A reconciliation of basic and diluted EPS for the three months ended January 31, 2012 and 2011 is presented below.

	Three Months	
In thousands except per share amounts	2012	2011
Net Income	$ 76,227	$ 84,440
Average shares of common stock outstanding for basic earnings per share	72,126	72,194
Contingently issuable shares under incentive compensation plans	307	320
Average shares of dilutive stock	72,433	72,514
Earnings Per Share of Common Stock:		
Basic	$ 1.06	$ 1.17
Diluted	$ 1.05	$ 1.16

4. Short-Term Debt Instruments

We have a $650 million three-year revolving syndicated credit facility that expires in January 2014. The facility has an option to expand up to $850 million. We pay an annual fee of $30,000 plus fifteen basis points for any unused amount up to $650 million. The facility provides a line of credit for letters of credit of $10 million, of which $2.9 million and $3.5 million was issued and outstanding at January 31, 2012 and October 31, 2011, respectively. These letters of credit are used to guarantee claims from self-insurance under our general and automobile liability policies. The credit facility bears interest based on the 30-day LIBOR rate plus from 65 to 150 basis points, based on our credit ratings. Amounts borrowed remain outstanding until repaid and do not mature daily. Due to the seasonal nature of our business, amounts borrowed can vary significantly during the year.

Our outstanding short-term bank borrowings, as included in "Bank debt" in the consolidated balance sheets, were $457.5 million and $331 million, as of January 31, 2012 and October 31, 2011, respectively, under our revolving syndicated credit facility in LIBOR cost-plus loans. During the three months ended January 31, 2012, short-term bank borrowings ranged from $328.5 million to $475.5 million, and interest rates ranged from 1.15% to 1.20% (weighted average of 1.18%). Our revolving syndicated credit facility's financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%, and our actual ratio was 53% at January 31, 2012.

For information on the initiation of a commercial paper program (CP program) subsequent to the period, see Note 14 to the consolidated financial statements in this Form 10-Q.

5. Capital Stock and Accelerated Share Repurchase

On January 4, 2012, we entered into an accelerated share repurchase (ASR) agreement where we purchased 800,000 shares of our common stock from an investment bank at the closing price that day of $33.77 per share. The settlement and retirement of those shares occurred on January 5, 2012. Total consideration paid to purchase the shares of $27 million was recorded in "Stockholders' equity" as a reduction in "Common stock" in the consolidated balance sheets.

As part of the ASR, we simultaneously entered into a forward sale contract with the investment bank that is expected to mature in 52 trading days, or March 21, 2012. Under the terms of the forward sale contract, the

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investment bank is required to purchase, in the open market, 800,000 shares of our common stock during the term of the contract to fulfill its obligation related to the shares it borrowed from third parties and sold to us. At settlement, we, at our option, are required to either pay cash or issue shares of our common stock to the investment bank if the investment bank's weighted average purchase price, less a $.09 per share discount, is higher than the January 4, 2012 closing price. The investment bank is required to pay us either cash or shares of our common stock, at our option, if the investment bank's weighted average price, less a $.09 per share discount, for the shares purchased is lower than the initial purchase closing price. We have accounted for this forward sale contract as an equity instrument under accounting guidelines. As the fair value of the forward sale contract at inception was zero, no accounting for the forward sale contract is required until settlement, as long as the forward sale continues to meet the requirements for classification as an equity instrument.

For further information on the subsequent settlement of the ASR by the investment bank on February 28, 2012, see Note 14 to the consolidated financial statements in this Form 10-Q.

6. Marketable Securities

We have marketable securities that are invested in money market and mutual funds that are liquid and actively traded on the exchanges. These securities are assets that are held in a rabbi trust established for our deferred compensation. For further information on the deferred compensation plans, see Note 9 to the consolidated financial statements.

We have classified these marketable securities as trading securities since their inception as the assets are held in a rabbi trust. Trading securities are recorded at fair value on the consolidated balance sheets with any gains or losses recognized currently in earnings. We do not intend to engage in active trading of the securities, and participants in the deferred compensation plans may redirect their investments at any time. Any participant's account that exceeds $25,000 upon retirement will be paid over five years upon retirement. An amount less than $25,000 in a participant's account upon retirement will be paid in a lump sum. We have matched the current portion of the deferred compensation liability with the current asset and noncurrent deferred compensation liability with the noncurrent asset; the current portion is included in "Other current assets" in the consolidated balance sheets.

The money market investments in the trust approximate fair value due to the short period of time to maturity. The fair values of the equity securities are based on the quoted market prices as traded on the exchanges. The composition of these securities as of January 31, 2012 and October 31, 2011 is as follows.

	January 31, 2012		October 31, 2011	
In thousands	Cost	Fair Value	Cost	Fair Value
Current trading securities:				
Money markets	$ —	$ —	$ —	$ —
Mutual funds	149	162	47	52
Total current trading securities	149	162	47	52
Noncurrent trading securities:				
Money markets	300	300	217	217
Mutual funds	1,611	1,778	1,107	1,222
Total noncurrent trading securities	1,911	2,078	1,324	1,439
Total trading securities	$ 2,060	$ 2,240	$ 1,371	$ 1,491

7. Financial Instruments and Related Fair Value

Derivative Assets and Liabilities under Master Netting Arrangements

We maintain brokerage accounts to facilitate transactions that support our gas cost hedging plans. The accounting guidance related to derivatives and hedging requires that we use a gross presentation, based on our election, for the fair value amounts of our derivative instruments and the fair value of the right to reclaim cash collateral. We use long position gas purchase options to provide some level of protection for our customers in the event of significant commodity price increases. As of January 31, 2012 and October 31, 2011, we had long gas purchase options providing total coverage of 44.1 million dekatherms and 38.1 million dekatherms, respectively. The long gas purchase options held at January 31, 2012 are for the period from March 2012 through February 2013.

Fair Value Measurements

We use financial instruments to mitigate commodity price risk for our customers. We also have marketable securities that are held in a rabbi trust established for certain of our deferred compensation plans. In developing our fair value measurements of these financial instruments, we utilize market data or assumptions about risk and the risks inherent in the inputs to the valuation technique. Fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the entity transacts. We classify fair value balances based on the observance of those inputs into the fair value hierarchy levels as set forth in the fair value accounting guidance and fully described in "Fair Value Measurements" in Note 1 to the consolidated financial statements in our Form 10-K for the year ended October 31, 2011.

The following table sets forth, by level of the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of January 31, 2012 and October 31, 2011. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their consideration within the fair value hierarchy levels. We have had no transfers between any level during the three months ended January 31, 2012 and 2011.

Recurring Fair Value Measurements as of January 31, 2012

In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value
Assets:				
Derivatives held for distribution operations	$ 1,776	$ —	$ —	$ 1,776
Debt and equity securities held as trading securities:				
Money markets	300	—	—	300
Mutual funds	1,940	—	—	1,940
Total fair value assets	$ 4,016	$ —	$ —	$ 4,016

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Recurring Fair Value Measurements as of October 31, 2011

In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value
Assets:				
Derivatives held for distribution operations	$ 2,772	$ —	$ —	$ 2,772
Debt and equity securities held as trading securities:				
Money markets	217	—	—	217
Mutual funds	1,274	—	—	1,274
Total fair value assets	$ 4,263	$ —	$ —	$ 4,263

Our utility segment derivative instruments are used in accordance with programs filed with or approved by the NCUC, the Public Service Commission of South Carolina (PSCSC) and the TRA to hedge the impact of market fluctuations in natural gas prices. These derivative instruments are accounted for at fair value each reporting period. In accordance with regulatory requirements, the net costs and the gains and losses related to these derivatives are reflected in purchased gas costs and ultimately passed through to customers through our purchased gas adjustment (PGA) procedures. In accordance with accounting provisions for rate-regulated activities, the unrecovered amounts related to these instruments are reflected as a regulatory asset or liability, as appropriate, in "Amounts due to customers" or "Amounts due from customers" in the consolidated balance sheets. These derivative instruments include exchange-traded derivative contracts. Exchange-traded contracts are generally based on unadjusted quoted prices in active markets and are classified within Level 1.

Trading securities include assets in a rabbi trust established for our deferred compensation plans and are included in "Marketable securities, at fair value" in the consolidated balance sheets. Securities classified within Level 1 include funds held in money market and mutual funds which are highly liquid and are actively traded on the exchanges.

In developing the fair value of our long-term debt, we use a discounted cash flow technique, consistently applied, that incorporates a developed discount rate using long-term debt similarly rated by credit rating agencies combined with the U.S. Treasury bench mark with consideration given to maturities, redemption terms and credit ratings similar to our debt issuances. The carrying amount and fair value of our long-term debt, including the current portion, are shown below.

In thousands	Carrying Amount	Fair Value
As of January 31, 2012	$ 675,000	$ 834,979
As of October 31, 2011	675,000	831,323

Quantitative and Qualitative Disclosures

The costs of our financial price hedging options for natural gas and all other costs related to hedging activities of our regulated gas costs are recorded in accordance with our regulatory tariffs approved by our state regulatory commissions, and thus are not accounted for as hedging instruments under derivative accounting standards. As required by the accounting guidance, the fair value amounts are presented on a gross basis and do not reflect any netting of asset and liability amounts or cash collateral amounts under master netting arrangements.

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The following table presents the fair value and balance sheet classification of our financial options for natural gas as of January 31, 2012 and October 31, 2011.

Fair Value of Derivative Instruments

In thousands	Fair Value January 31, 2012	Fair Value October 31, 2011
Derivatives Not Designated as Hedging Instruments under Derivative Accounting Standards:		
Asset Financial Instruments:		
Current Assets — Gas purchase derivative assets (March 2012-February 2013)	$ 1,776	
Current Assets — Gas purchase derivative assets (December 2011-October 2012)		$ 2,772

We purchase natural gas for our regulated operations for resale under tariffs approved by state regulatory commissions. We recover the cost of gas purchased for regulated operations through PGA procedures. Our risk management policies allow us to use financial instruments to hedge commodity price risks, but not for speculative trading. The strategy and objective of our hedging programs is to use these financial instruments to provide some level of protection against significant price increases. Accordingly, the operation of the hedging programs on the regulated utility segment as a result of the use of these financial derivatives is initially recorded as a component of deferred gas costs and recognized in the consolidated statements of comprehensive income as a component of cost of gas when the related costs are recovered through our rates.

The following table presents the impact that financial instruments not designated as hedging instruments under derivative accounting standards would have had on our consolidated statements of comprehensive income for the three months ended January 31, 2012 and 2011, absent the regulatory treatment under our approved PGA procedures.

In thousands	Amount of Loss Recognized on Derivatives Instruments		Amount of Loss Deferred Under PGA Procedures		Location of Loss Recognized through PGA Procedures
	Three Months Ended January 31,		Three Months Ended January 31,		
	2012	2011	2012	2011	
Gas purchase options	$2,923	$4,221	$2,923	$4,221	Cost of Gas

In Tennessee, the cost of gas purchase options and all other costs related to hedging activities up to 1% of total annual gas costs are approved for recovery under the terms and conditions of our TIP approved by the TRA. In South Carolina, the costs of gas purchase options are subject to the terms and conditions of our gas hedging plan approved by the PSCSC. In North Carolina, the costs associated with our hedging program are treated as gas costs subject to an annual cost review proceeding by the NCUC.

Risk Management

Our financial derivative instruments do not contain material credit-risk-related or other contingent features that could require us to make accelerated payments.

We seek to identify, assess, monitor and manage risk in accordance with defined policies and procedures under an Enterprise Risk Management program. In addition, we have an Energy Price Risk Management Committee that monitors compliance with our hedging programs, policies and procedures.

8. Commitments and Contingent Liabilities

Long-term contracts

We routinely enter into long-term gas supply commodity and capacity commitments and other agreements that commit future cash flows to acquire services we need in our business. These commitments include pipeline and storage capacity contracts and gas supply contracts to provide service to our customers and telecommunication and information technology contracts and other purchase obligations. The time periods for pipeline and storage capacity contracts range from one to twenty years. The time periods for gas supply contracts are one year. The time periods for the telecommunications and technology outsourcing contracts, maintenance fees for hardware and software applications, usage fees, local and long-distance costs and wireless service range from one to three years. Other purchase obligations consist primarily of commitments for pipeline products, vehicles and contractors.

Certain storage and pipeline capacity contracts require the payment of demand charges that are based on rates approved by the Federal Energy Regulatory Commission (FERC) in order to maintain our right to access the natural gas storage or the pipeline capacity on a firm basis during the contract term. The demand charges that are incurred in each period are recognized in the consolidated statements of comprehensive income as part of gas purchases and included in cost of gas.

Leases

We lease certain buildings, land and equipment for use in our operations under noncancelable operating leases. We account for these leases by recognizing the future minimum lease payments as expense on a straight-line basis over the respective minimum lease terms under current accounting practice.

Legal

We have only routine litigation in the normal course of business. We do not expect any of these routine litigation matters to have a material effect on our financial position, results of operations or cash flows.

Letters of Credit

We use letters of credit to guarantee claims from self-insurance under our general and automobile liability policies. We had $2.9 million in letters of credit that were issued and outstanding at January 31, 2012. Additional information concerning letters of credit is included in Note 4 to the consolidated financial statements.

Environmental Matters

Our three regulatory commissions have authorized us to utilize deferral accounting in connection with environmental costs. Accordingly, we have established regulatory assets for actual environmental costs incurred and for estimated environmental liabilities recorded.

In October 1997, we entered into a settlement with a third party with respect to nine manufactured gas plant (MGP) sites that we have owned, leased or operated that released us from any investigation and remediation liability. Although no such claims are pending or, to our knowledge, threatened, the settlement did not cover any third-party claims for personal injury, death, property damage and diminution of property value or natural resources.

There are four other MGP sites located in Hickory and Reidsville, North Carolina, Nashville, Tennessee and Anderson, South Carolina that we have owned, leased or operated. At our Reidsville site, we have performed soil remediation work and will be performing a groundwater remediation assessment under our North Carolina Department of Environment and Natural Resources (NCDENR) approved plan. Remediation at this site is scheduled to be completed in our fiscal year 2012, and we have incurred $.6 million of remediation costs through January 31, 2012.

As part of a voluntary agreement with the NCDENR, we conducted and completed soil remediation for the Hickory, North Carolina MGP site. The soil remediation report was filed with the NCDENR in October 2010. We continue to conduct periodic groundwater monitoring at this site in accordance with our site remediation plan. We have incurred $1.4 million of remediation costs on this site through January 31, 2012.

In November 2008, we submitted our final report of the remediation of the Nashville MGP holding tank site to the Tennessee Department of Environment and Conservation (TDEC). Remediation has been completed, and a consent order imposing usage restrictions on the property was approved and signed by the TDEC in June 2010. The public comment period has ended, and we continue to conduct semi-annual groundwater monitoring at the site per the final consent order. We have incurred $1.5 million of remediation costs through January 31, 2012.

In connection with our 2003 North Carolina Natural Gas Corporation (NCNG) acquisition, several MGP sites owned by NCNG were transferred to a wholly owned subsidiary of Progress Energy, Inc. (Progress) prior to closing. Progress has complete responsibility for performing all of NCNG's remediation obligations to conduct testing and clean-up at these sites, including both the costs of such testing and clean-up and the implementation of any affirmative remediation obligations that NCNG has related to the sites. Progress' responsibility does not include any third-party claims for personal injury, death, property damage, and diminution of property value or natural resources. We know of no such pending or threatened claims.

During 2008, we became aware of and began investigating soil and groundwater molecular sieve contamination concerns at our Huntersville liquefied natural gas (LNG) facility. The molecular sieve and the related contaminated soil were removed and properly disposed, and in June 2010, we received a determination letter from the NCDENR that no further soil remediation would be required for the Huntersville LNG molecular sieve issue. In September 2011, we received a letter from the NCDENR indicating their desire to enter into an Administrative Consent Order (ACO) addressing the remaining groundwater issues at the site and imposing a fine in an amount that will be less than $100,000. We are currently negotiating the ACO. Plans to investigate the extent of the groundwater contamination related to the sieve burial will be developed upon the final negotiation of the ACO. The Huntersville LNG facility also was originally coated with lead-based paint. As a precautionary measure to ensure that no lead contamination occurs, removal of lead-based paint from the site was initiated in spring 2010. We have incurred $3.2 million to remediate the Huntersville LNG site through January 31, 2012. The LNG tank is scheduled for lead-based paint removal in our fiscal year 2012. Additional facilities at our Huntersville LNG plant site are being evaluated for lead-based paint removal with work scheduled for our fiscal year 2012.

Our Nashville LNG facility was also originally coated with lead-based paint. We have incurred $.4 million of remediation costs through January 31, 2012. This work is scheduled to be completed in our fiscal year 2012.

We are transitioning away from owning and maintaining our own petroleum underground storage tanks (USTs). Our Charlotte, North Carolina district continues to operate USTs. During 2011, our Greenville, South Carolina and Greensboro and Salisbury, North Carolina districts had their tanks removed, and we do not anticipate significant environmental remediation with respect to the removal process. The South Carolina Department of

Health and Environmental Control requested that we conduct an initial groundwater assessment at our Greenville, South Carolina site to determine its current groundwater quality condition. This assessment is scheduled to be completed in our fiscal year 2012. As of January 31, 2012, our estimated undiscounted environmental liability for USTs for which we retain remediation responsibility is $.3 million.

One of our operating districts has coatings containing asbestos on some of their pipelines. We have educated our employees on the hazards of asbestos and implemented procedures for removing these coatings from our pipelines when we must excavate and expose small portions of the pipeline. Lead-based paint is being removed at multiple LNG facilities that we own. Employees have been trained on the hazards of lead exposure, and we have engaged independent environmental contractors to remove and dispose of the lead-based paint at these facilities.

As of January 31, 2012, our estimated undiscounted environmental liability totaled $2.4 million, and consisted of $1 million for the MGP sites for which we retain remediation responsibility, $1.1 million for the LNG facilities and $.3 million for the USTs not yet remediated.

Further evaluation of the MGP, LNG and UST sites and removal of lead-based paint could significantly affect recorded amounts; however, we believe that the ultimate resolution of these matters will not have a material effect on our financial position, results of operations or cash flows.

Additional information concerning commitments and contingencies is set forth in Note 8 to the consolidated financial statements of our Form 10-K for the year ended October 31, 2011.

9. Employee Benefit Plans

Components of the net periodic benefit cost for our defined benefit pension plans and our other postretirement employee benefits (OPEB) plan for the three months ended January 31, 2012 and 2011 are presented below.

	Qualified Pension		Nonqualified Pension		Other Benefits	
In thousands	2012	2011	2012	2011	2012	2011
Service cost	$ 2,475	$ 2,225	$ 10	$ 11	$ 347	$ 350
Interest cost	2,650	2,700	51	52	337	374
Expected return on plan assets	(5,125)	(5,150)	—	—	(388)	(384)
Amortization of transition obligation	—	—	—	—	167	167
Amortization of prior service (credit) cost	(550)	(550)	20	5	—	—
Amortization of actuarial loss	1,375	775	12	10	—	—
Total	$ 825	$ —	$ 93	$ 78	$ 463	$ 507

In January 2012, we contributed $.5 million to the money purchase pension plan. We anticipate that we will contribute the following amounts to our other plans in 2012.

In thousands		
Nonqualified pension plan	$	517
Qualified pension plan		—
OPEB plan		1,600

We have a defined contribution restoration (DCR) plan that we fund annually and that covers all officers at the vice president level and above. For the three months ended January 31, 2012, we contributed $.4 million to this plan. Participants may not contribute to the DCR plan. We have a voluntary deferral plan for the benefit of all director-level employees and officers; company contributions are not made to this plan. Both deferred compensation plans are funded through a rabbi trust with a bank as the trustee. As of January 31, 2012, we have a liability of $2.3 million for these plans.

See Note 6 and Note 7 to the consolidated financial statements in this Form 10-Q for information on the investments in marketable securities that are held in the trust.

10. Employee Share-Based Plans

Under our shareholder approved Incentive Compensation Plan (ICP), eligible officers and other participants are awarded units that pay out depending upon the level of performance achieved by Piedmont during three-year incentive plan performance periods. Distribution of those awards may be made in the form of shares of common stock and withholdings for payment of applicable taxes on the compensation. These plans require that a minimum threshold performance level be achieved in order for any award to be distributed. For the three months ended January 31, 2012 and 2011, we recorded compensation expense, and as of January 31, 2012 and October 31, 2011, we have accrued a liability for these awards based on the fair market value of our stock at the end of each quarter. The liability is re-measured to market value at the settlement date.

In December 2010, a long-term retention stock unit award under the ICP (where a stock unit equals one share of our common stock upon vesting) was approved for eligible officers and other participants to support our succession planning and retention strategies. This retention stock unit award will vest for participants who have met the retention requirements at the end of a three-year period ending in December 2013 in the form of shares of common stock and withholdings for payment of applicable taxes on the compensation. The Compensation Committee of our Board of Directors has the discretion to accelerate the vesting of a participant's units. For the three months ended January 31, 2012 and 2011, we recorded compensation expense, and as of January 31, 2012 and October 31, 2011, we have accrued a liability for these awards based on the fair market value of our stock at the end of the quarter. The liability is re-measured to market value at the settlement date.

Also under our approved incentive plan, 64,700 unvested retention stock units were granted to our President and Chief Executive Officer in December 2011. During the five-year vesting period, any dividends equivalents will accrue on these stock units and be converted into additional units at the same rate and based on the closing price on the same payment date as dividends on our common stock. The stock units will vest, payable in the form of shares of common stock and withholdings for payment of applicable taxes on the compensation, over a five-year period only if he is an employee on each vesting date. In accordance with the vesting schedule, 20% of the units vest on December 15, 2014, 30% of the units vest on December 15, 2015 and 50% of the units vest on December 15, 2016. For the three months ended January 31, 2012, we recorded compensation expense, and as of January 31, 2012, we have accrued a liability for these awards based on the fair market value of our stock at the end of the quarter. The liability is re-measured to market value at the settlement date.

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The compensation expense related to the incentive compensation plans for the three months ended January 31, 2012 and 2011, and the amounts recorded as liabilities as of January 31, 2012 and October 31, 2011 are presented below.

	Three Months	
In thousands	2012	2011
Compensation expense	$1,575	$922

	January 31, 2012	October 31, 2011
Liability	$6,590	$5,015

On a quarterly basis, we issue shares of common stock under the employee stock purchase plan and have accounted for the issuance as an equity transaction. The exercise price is calculated as 95% of the fair market value on the purchase date of each quarter where fair market value is determined by calculating the mean average of the high and low trading prices on the purchase date.

11. Equity Method Investments

The consolidated financial statements include the accounts of wholly owned subsidiaries whose investments in joint venture, energy-related businesses are accounted for under the equity method. Our ownership interest in each entity is included in "Equity method investments in non-utility activities" in the consolidated balance sheets. Earnings or losses from equity method investments are included in "Income from equity method investments" in the consolidated statements of comprehensive income.

We own 21.49% of the membership interests in Cardinal Pipeline Company, L.L.C. (Cardinal), a North Carolina limited liability company. Cardinal owns and operates an intrastate natural gas pipeline in North Carolina and is regulated by the NCUC.

In October 2009, we reached an agreement with Progress Energy Carolinas, Inc. to provide natural gas delivery service to a power generation facility to be built at their Wayne County, North Carolina site. To provide the additional delivery service, we have executed an agreement with Cardinal, which was approved by the NCUC in May 2010, to expand our firm capacity requirement by 149,000 dekatherms per day to serve Progress Energy Carolinas. This will require Cardinal to spend an estimated $48 million for a new compressor station and expanded meter stations in order to increase the capacity of its system by up to 199,000 dekatherms per day of firm capacity for us and another customer. As an equity venture partner of Cardinal, we will invest an estimated $10.3 million in Cardinal's system expansion. Capital contributions related to this system expansion began in January 2011 and will continue on a periodic basis through September 2012. As of January 31, 2012, our current fiscal year contributions related to this expansion were $1.8 million, and our total contributions related to this expansion were $8 million.

The members' capital will be replaced with permanent financing with a target overall capital structure of 45-50% debt and 50-55% equity after the project is placed into service, scheduled to be June 2012. Our service subscription to Cardinal's capacity following the system expansion will increase from approximately 37% to approximately 53%.

We have related party transactions as a transportation customer of Cardinal, and we record in cost of gas the transportation costs charged by Cardinal. For each period of the three months ended January 31, 2012 and 2011, these transportation costs and the amounts we owed Cardinal as of January 31, 2012 and October 31, 2011 are as follows.

	Three Months	
In thousands	2012	2011
Transportation costs	$1,035	$1,035
	January 31, 2012	October 31, 2011
Trade accounts payable	$349	$349

We own 40% of the membership interests in Pine Needle LNG Company, L.L.C. (Pine Needle), a North Carolina limited liability company. Pine Needle owns an interstate LNG storage facility in North Carolina and is regulated by the FERC.

We have related party transactions as a customer of Pine Needle, and we record in cost of gas the storage costs charged by Pine Needle. For each period of the three months ended January 31, 2012 and 2011, these gas storage costs and the amounts we owed Pine Needle as of January 31, 2012 and October 31, 2011 are as follows.

	Three Months	
In thousands	2012	2011
Gas storage costs	$2,519	$2,926
	January 31, 2012	October 31, 2011
Trade accounts payable	$849	$849

We own 15% of the membership interests in SouthStar Energy Services LLC (SouthStar), a Delaware limited liability company. The other member is Georgia Natural Gas Company (GNGC), a wholly-owned subsidiary of AGL Resources, Inc. SouthStar primarily sells natural gas to residential, commercial and industrial customers in the southeastern United States and Ohio with most of its business being conducted in the unregulated retail gas market in Georgia. We account for our 15% membership interest in SouthStar using the equity method, as we have board representation with voting rights equal to GNGC on significant governance matters and policy decisions, and thus, exercise significant influence over the operations of SouthStar.

We have related party transactions as we sell wholesale gas supplies to SouthStar, and we record in operating revenues the amounts billed to SouthStar. For each period of the three months ended January 31, 2012 and 2011, our operating revenues from these sales and the amounts SouthStar owed us as of January 31, 2012 and October 31, 2011 are as follows.

	Three Months	
In thousands	2012	2011
Operating revenues	$(112)	$(31)
	January 31, 2012	October 31, 2011
Trade accounts receivable	$356	$736

Piedmont Hardy Storage Company, LLC, a wholly owned subsidiary of Piedmont, owns 50% of the membership interests in Hardy Storage Company, LLC (Hardy Storage), a West Virginia limited liability company. Hardy Storage owns and operates an underground interstate natural gas storage facility located in Hardy and Hampshire Counties, West Virginia, that is regulated by the FERC.

We have related party transactions as a customer of Hardy Storage and record in cost of gas the storage costs charged by Hardy Storage. For each period of the three months ended January 31, 2012 and 2011, these gas storage costs and the amounts we owed Hardy Storage as of January 31, 2012 and October 31, 2011 are as follows.

	Three Months	
In thousands	2012	2011
Gas storage costs	$2,425	$2,425
	January 31, 2012	October 31, 2011
Trade accounts payable	$808	$808

12. Variable Interest Entities

Under accounting guidance, a variable interest entity (VIE) is a legal entity that conducts a business or holds property whose equity, by design, has any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or where equity owners do not receive expected losses or returns. An entity may have an interest in a VIE through ownership or other contractual rights or obligations and that interest changes as the entity's net assets change. The consolidating investor is the entity that has the power to direct the activities of a VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

As of January 31, 2012, we have determined that we are not the primary beneficiary, as defined by the authoritative guidance related to consolidations, in any of our equity method investments, as discussed in Note 11 to the consolidated financial statements. Based on our involvement in these investments, we do not have the power to direct the activities of these investments that most significantly impact the VIE's economic performance. As we are not the consolidating investor, we will continue to apply equity method accounting to these investments as discussed in Note 11 to the consolidated financial statements. Our maximum loss exposure related to these equity method investments is limited to our equity investment in each entity. As of January 31, 2012 and October 31, 2011, our investment balances are as follows.

In thousands	January 31, 2012	October 31, 2011
Cardinal	$ 20,293	$ 18,323
Pine Needle	18,757	18,690
SouthStar	21,494	17,536
Hardy Storage	31,082	30,572
Total equity method investments in non-utility activities	$ 91,626	$ 85,121

We have also reviewed various lease arrangements, contracts to purchase, sell or deliver natural gas and other agreements in which we hold a variable interest. In these cases, we have determined that we are not the primary beneficiary of the related VIE because we do not have the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, or the obligation to absorb losses of the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

13. Business Segments

We have two reportable business segments, regulated utility and non-utility activities. Our segments are identified based on products and services, regulatory environments and our current corporate organization and business decision-making activities. The regulated utility segment is the gas distribution business, including the operations of merchandising and its related service work and home warranty programs, with activities conducted by the parent company. Operations of our non-utility activities segment are comprised of our equity method investments in joint ventures that are held by our wholly owned subsidiaries.

Operations of the regulated utility segment are reflected in "Operating Income" in the consolidated statements of comprehensive income. Operations of the non-utility activities segment are included in the consolidated statements of comprehensive income in "Income from equity method investments" and "Non-operating income."

We evaluate the performance of the regulated utility segment based on margin, operations and maintenance expenses and operating income. We evaluate the performance of the non-utility activities segment based on earnings from the ventures. The basis of segmentation and the basis of the measurement of segment profit or loss are the same as reported in the consolidated financial statements in our Form 10-K for the year ended October 31, 2011.

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Operations by segment for the three months ended January 31, 2012 and 2011 are presented below.

In thousands	Regulated Utility		Non-utility Activities		Total	
	2012	2011	2012	2011	2012	2011
Three Months						
Revenues from external customers	$ 471,840	$ 652,056	$ —	$ —	$ 471,840	$ 652,056
Margin	220,237	230,006	—	—	220,237	230,006
Operations and maintenance expenses	58,397	51,058	23	30	58,420	51,088
Income from equity method investments	—	—	6,292	7,756	6,292	7,756
Operating income (loss) before income taxes	127,040	142,804	(107)	(119)	126,933	142,685
Income before income taxes	119,581	131,689	6,185	7,638	125,766	139,327

Reconciliations to the consolidated statements of comprehensive income for the three months ended January 31, 2012 and 2011 are presented below.

In thousands	Three Months	
	2012	2011
Operating Income:		
Segment operating income before income taxes	$ 126,933	$ 142,685
Utility income taxes	(47,221)	(51,935)
Non-utility activities before income taxes	107	119
Operating income	$ 79,819	$ 90,869
Net Income:		
Income before income taxes for reportable segments	$ 125,766	$ 139,327
Income taxes	(49,539)	(54,887)
Net income	$ 76,227	$ 84,440

14. Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. All subsequent events of which we are aware were evaluated. For information on subsequent event disclosure related to regulatory matters, see Note 2 to the consolidated financial statements.

On February 28, 2012, the ASR settled. We received $.5 million from the investment bank and will record this amount in "Stockholder's equity" as an addition to "Common Stock." The $.5 million was the difference between the investment bank's weighted average purchase price of $33.25 per share less a discount of $.09 per share for a settlement price of $33.16 per share and the initial purchase closing price of $33.77 per share multiplied by 800,000 shares.

In March 2012, we established a $650 million unsecured CP program. The notes issued under the CP program will have maturities not to exceed 397 days from the date of issuance and will be backstopped by our existing $650 million revolving syndicated credit facility expiring January 25, 2014. The amount outstanding under the revolving syndicated credit facility and the CP program, either individually or in the aggregate, shall not exceed $650 million. Any borrowings under the CP program will rank equally with our other unsubordinated and unsecured debt. The short-term notes under the CP program will not be registered under the Securities Act of 1933 for public offering and may not be offered or sold by us absent registration or exemption from registration requirements. We will be issuing the notes pursuant to an exemption from registration.

In February 2012, we secured pricing confirmations from lenders that price $300 million of private placement long-term debt with the transaction expected to close on March 27, 2012. We will be issuing $100 million on or around July 16, 2012 with an interest rate of 3.47%. On or around October 15, 2012, we will be issuing the remaining $200 million with an interest rate of 3.57%. Both issuances will mature in fifteen years on or about July 16, 2027. The blended interest rate for these debt issuances is 3.54%. These proceeds will be used for general corporate purposes, including the repayment of short-term debt incurred in part for funding of capital expenditures for power generation gas delivery service projects.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

This report, as well as other documents we file with the Securities and Exchange Commission (SEC), may contain forward-looking statements. In addition, our senior management and other authorized spokespersons may make forward-looking statements in print or orally to analysts, investors, the media and others. These statements are based on management's current expectations from information currently available and are believed to be reasonable and made in good faith. However, the forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those projected in the statements. Factors that may make the actual results differ from anticipated results include, but are not limited to the following, as well as those discussed in Part II, Item 1A. Risk Factors of this Form 10-Q:

- Regulatory issues. Deregulation, regulatory restructuring and other regulatory issues may affect us and those from whom we purchase natural gas transportation and storage service, including issues that affect allowed rates of return, terms and conditions of service, rate structures and financings. We monitor our ability to earn appropriate rates of return and initiate general rate proceedings as needed.
- Customer growth and consumption. Residential, commercial, industrial and power generation growth and energy consumption in our service areas may change. The ability to retain and grow our customer base, the pace of that growth and the levels of energy consumption are impacted by general business and economic conditions, such as interest rates, inflation, fluctuations in the capital markets and the overall strength of the economy in our service areas and the country, and by fluctuations in the wholesale prices of natural gas and competitive energy sources. Large-volume industrial customers may switch to alternate fuels or bypass our systems or shift to special competitive contracts or to tariff rates that are at lower-per unit margins than that customer's existing rate.
- Competition in the energy industry. We face competition in the energy industry, such as from electric companies, energy marketing and trading companies, fuel oil and propane dealers, renewable energy companies and coal companies, and we expect this competitive environment to continue.
- The capital-intensive nature of our business. In order to maintain growth, we must invest in our natural gas transmission and distribution systems each year. The cost of and the ability to complete these capital projects may be affected by the ability to obtain and the cost of obtaining governmental approvals, compliance with federal and state pipeline safety and integrity regulations, cost and timing of project development-related contracts and approvals, project development delays, federal and state tax policies, and the cost and availability of labor and materials. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost and timing of a project.

- Access to capital markets. Our internally generated cash flows are not adequate to finance the full cost of capital expenditures. As a result, we rely on access to both short-term and long-term capital markets as a significant source of liquidity for capital requirements not satisfied by cash flows from operations. Changes in the capital markets, our financial condition or the financial condition of our lenders or investors could affect access to and cost of capital.
- Changes in the availability and cost of natural gas. To meet firm customer requirements, we must acquire sufficient gas supplies and pipeline capacity to ensure delivery to our distribution system while also ensuring that our supply and capacity contracts allow us to remain competitive. Natural gas is an unregulated commodity market subject to supply and demand and price volatility. Producers, marketers and pipelines are subject to operating, regulatory and financial risks associated with exploring, drilling, producing, gathering, marketing and transporting natural gas and have risks that increase our exposure to supply and price fluctuations. Since such risks may affect the availability and cost of natural gas, they also may affect the competitive position of natural gas relative to other energy sources.
- Changes in weather conditions. Weather conditions and other natural phenomena can have a material impact on our earnings. Severe weather conditions, including destructive weather patterns such as hurricanes, tornadoes and floods, can impact our customers, our suppliers and the pipelines that deliver gas to our distribution system and our distribution and transmission assets. Weather conditions directly influence the supply, demand, distribution and cost of natural gas.
- Changes in and cost of compliance with laws and regulations. We are subject to extensive federal, state and local laws and regulations. Environmental, safety, system integrity, tax and other laws and regulations, including those related to carbon regulation, may change. Compliance with such laws and regulations could increase capital or operating costs, affect our reported earnings or cash flows, increase our liabilities or change the way our business is conducted.
- Ability to retain and attract professional and technical employees. To provide quality service to our customers and meet regulatory requirements, we are dependent on our ability to recruit, train, motivate and retain qualified employees.
- Changes in accounting regulations and practices. We are subject to accounting regulations and practices issued periodically by accounting standard-setting bodies. New accounting standards may be issued that could change the way we record revenues, expenses, assets and liabilities, and could affect our reported earnings or increase our liabilities.
- Earnings from our equity method investments. We invest in companies that have risks that are inherent in their businesses, and these risks may negatively affect our earnings from those companies.
- Changes in outstanding shares. The number of outstanding shares may fluctuate due to new issuances or repurchases under our Common Stock Open Market Purchase Program.

Other factors may be described elsewhere in this report. All of these factors are difficult to predict, and many of them are beyond our control. For these reasons, you should not rely on these forward-looking statements when making investment decisions. When used in our documents or oral presentations, the words "expect," "believe," "project," "anticipate," "intend," "should," "could," "assume," "estimate," "forecast," "future," "indicate," "outlook," "plan," "predict," "seek," "target," "would" and variations of such words and similar expressions are intended to identify forward-looking statements.

Forward-looking statements are based on information available to us as of the date they are made, and we do not undertake any obligation to update publicly any forward-looking statement either as a result of new information, future events or otherwise except as required by applicable laws and regulations. Our reports on Form 10-K, Form 10-Q and Form 8-K and amendments to these reports are available at no cost on our website at www.piedmontng.com as soon as reasonably practicable after the report is filed with or furnished to the SEC.

Overview

Piedmont Natural Gas Company, Inc., which began operations in 1951, is an energy services company whose principal business is the distribution of natural gas to over one million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including 53,000 customers served by municipalities who are our wholesale customers. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, and regulated interstate natural gas storage and intrastate natural gas transportation.

In 1994, our predecessor, which was incorporated in 1950 under the same name, was merged into a newly formed North Carolina corporation for the purpose of changing our state of incorporation to North Carolina.

In the Carolinas, our service area is comprised of numerous cities, towns and communities. We provide service to Anderson, Gaffney, Greenville and Spartanburg in South Carolina and Charlotte, Salisbury, Greensboro, Winston-Salem, High Point, Burlington, Hickory, Indian Trail, Spruce Pine, Reidsville, Fayetteville, New Bern, Wilmington, Tarboro, Elizabeth City, Rockingham and Goldsboro in North Carolina. In North Carolina, we also provide wholesale natural gas service to the cities of Greenville, Rocky Mount and Wilson. In Tennessee, our service area is the metropolitan area of Nashville, including wholesale natural gas service to the cities of Gallatin and Smyrna.

We have two reportable business segments, regulated utility and non-utility activities. The regulated utility segment is the largest segment of our business with approximately 97% of our consolidated assets. Factors critical to the success of the regulated utility include operating a safe, reliable natural gas distribution system and the ability to recover the costs and expenses of the business in the rates charged to customers. For the three months ended January 31, 2012, 95% of our earnings before taxes came from our regulated utility segment. The non-utility activities segment consists of our equity method investments in joint venture, energy-related businesses that are involved in unregulated retail natural gas marketing, and regulated interstate natural gas storage and intrastate natural gas transportation. For the three months ended January 31, 2012, 5% of our earnings before taxes came from our non-utility segment, which consisted of 2% from regulated non-utility activities and 3% from unregulated non-utility activities. For further information on equity method investments and business segments, see Note 11 and Note 13, respectively, to the consolidated financial statements.

Our utility operations are regulated by the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina and the Tennessee Regulatory Authority (TRA) as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. The NCUC also regulates us as to the issuance of long-term debt and equity securities. We are also subject to or affected by various federal regulations. These federal regulations include regulations that are particular to the natural gas industry, such as regulations of the Federal Energy Regulatory Commission that affect the purchase and sale of and the prices paid for the interstate transportation and storage of natural gas, regulations of the U.S. Department of Transportation (DOT) that affect the design, construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency relating to the environment. In addition, we are subject to numerous other regulations, such as those relating to employment and benefit practices, which are generally applicable to companies doing business in the United States of America.

Our regulatory commissions approve rates and tariffs that are designed to give us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our operating expenses and to earn a fair rate of return on invested capital for our shareholders. Our ability to earn our authorized rates of return is based in part on our ability to reduce or eliminate regulatory lag and also by improved rate designs that decouple the recovery of our approved margins from customer usage patterns impacted by seasonal weather patterns and customer conservation.

In North Carolina, a margin decoupling mechanism provides for the recovery of our approved margin from residential and commercial customers on an annual basis independent of consumption patterns. The margin decoupling mechanism results in semi-annual rate adjustments to refund any over-collection of margin or recover any under-collection of margin. Currently, we have weather normalization adjustment (WNA) mechanisms in South Carolina and Tennessee that partially offset the impact of colder- or warmer-than-normal winter weather on bills rendered during the months of November through March for residential and commercial customers. The WNA formula calculates the actual weather variance from normal, using 30 years of history, which increases revenues when weather is warmer than normal and decreases revenues when weather is colder than normal. The WNA formula does not ensure full recovery of approved margin during periods when customer consumption patterns significantly vary from consumption patterns used to establish the WNA factors. The gas cost portion of our costs is recoverable through purchased gas adjustment (PGA) procedures and is not affected by the margin decoupling mechanism or the WNA.

We continually assess alternative rate structures and cost recovery mechanisms that are more appropriate to the changing energy economy. The traditional utility rate design provides for the collection of margin revenue based on volumetric throughput which can be affected by customer consumption patterns, weather, conservation, price levels for natural gas or general economic conditions. These alternative rate structures and cost recovery mechanisms are rate designs and mechanisms that allow utilities to encourage energy efficiency and conservation by separating or decoupling the link between energy consumption and margin revenues, thereby aligning the interests of shareholders and customers. In North Carolina, we have decoupled residential and commercial rates. In South Carolina, we operate under a rate stabilization mechanism that achieves the objectives of margin decoupling for residential and commercial customers with a one year lag. In Tennessee, as a result of our 2012 rate case settlement, we will shift 37% of our cost recovery to fixed charges rather than 29% with a resulting decrease of volumetric charges to 63% rather than 71%. For the three months ended January 31, 2012, these and other rate designs stabilized our gas utility margin by providing fixed recovery of 69% of our utility margins, including margin decoupling in North Carolina, facilities charges to our customers and fixed-rate contracts; semi-fixed recovery of 22% of our utility margins, including the rate stabilization mechanism in South Carolina and WNA in South Carolina and Tennessee; and volumetric or periodic renegotiation of 9% of our utility margins. For the three months ended January 31, 2012, the margin decoupling mechanism in North Carolina increased margin by $16.8 million, and the WNA in South Carolina and Tennessee increased margin by $7.1 million.

Our strategic directives have a customer-centered approach and reflect what we believe is the inherent benefit of natural gas compared to other types of energy. Our overall corporate focus is to expand our core natural gas and complementary energy-related businesses to enhance shareholder value. This focus includes traditional growth in the core residential, commercial and industrial markets, growth in the power generation market, supply diversity and complementary energy-related investments and natural gas end use technology. We want our customers to choose us because of the value of natural gas and the quality of our service to them. We strive to achieve excellence in service to our customers and in our business operations with every customer contact we make. We pursue business practices to promote a sustainable enterprise by reducing our impact on the environment, developing strong communities in which we operate and fostering increased awareness and use of natural gas. We support our employees with improved processes and technology to better serve our customers and to add value for our shareholders while continuing to build on our healthy, high performance culture in order to recruit, retain and motivate our workforce.

The safety of our system, the public and our employees is a critical component to our ongoing success as a company. We are subject to DOT and state regulation of our pipeline and related facilities and have ongoing programs to inspect our system for corrosion and leaks. We anticipate federal legislative and regulatory enactments that will increase in scope and add further requirements to our transmission pipeline safety and integrity programs that include leak detection surveys, periodic valve maintenance, periodic corrosion and atmospheric corrosion inspections, cathodic protection, in-line inspection devices, hydrostatic and compressed air pressure testings of new facilities and other evaluation methods. We will continue our efforts to educate the public about our pipeline system in an effort to decrease third party excavation damage, which is the greatest cause of any pipeline damage on our system. We encourage focused efforts to improve the safety of our industry as a whole.

The safeguarding of our information technology infrastructure is important to our business. There is risk associated with the unauthorized access of digital data with the intent to misappropriate information, corrupt data or cause operational disruptions. To protect confidential customer, vendor, financial and employee information, we believe we have appropriate levels of security measures in place to secure our information systems from cybersecurity attacks or breaches. We also have a comprehensive identity theft protection program to protect customer information, as well as a cybersecurity insurance policy.

We continue to work toward a business model that positions us for long-term success in a lower carbon energy economy with a focus on future growth opportunities that support new clean energy technologies and energy efficiencies. We are seeking opportunities for regulatory innovation and strategic alliances to advance our customers' interests in energy conservation, efficiency and environmental stewardship. We continue our efforts to promote the benefits of natural gas with promotion efforts aimed at educating consumers on the benefits of natural gas compared to other energy sources as well as advocating the benefits of natural gas to prospective customers in our communities. We are promoting the direct use of natural gas in more homes, businesses, industries and vehicles as we strongly believe that the expanded use of clean, efficient, abundant and domestic natural gas with its relatively low emissions can help revitalize our economy, reduce both overall energy consumption and greenhouse gas emissions and enhance our national energy security. We also promote and market the cost and environmental benefits of natural gas to power generation customers in our market area.

Our financial strength and flexibility is critical to our success as a company. We will continue our stewardship to maintain our financial strength, which translates to continued access to capital markets. We continue to evaluate the strength of financial institutions with which we have working relationships to ensure access to funds for operations and capital investments. Our capital plan includes maintaining a long-term debt-to-capitalization ratio within a range of 45% to 50%. We will continue to control our operating costs, implement new technologies and work with our state regulators to maintain fair rates of return and balance the interests of our customers and shareholders. We also seek to maintain a strong balance sheet and investment-grade credit ratings to support our operating and investment needs.

We invest in joint ventures to complement or supplement income from our regulated utility operations if an opportunity aligns with our overall business strategies and allows us to leverage our core competencies. We analyze and evaluate potential projects with a major factor being projected rates of return commensurate with the risk of such projects. We participate in the governance of our ventures by having management representatives on the governing boards. We monitor actual performance against expectations, and any decision to exit an existing joint venture would be based on many factors, including performance results and continued alignment with our business strategies.

Executive Summary

Natural gas supply production from shale basins, such as the Marcellus, Barnett and Haynesville as well as other shale gas producing areas, continues to provide supply stability and price moderation for natural gas as a commodity. The lower price of natural gas has allowed us to significantly lower the cost of gas to our customers in North Carolina, South Carolina and Tennessee. As a result, natural gas continues to have a price advantage, as well as an environmental advantage, over many other fuels.

We have taken advantage of the growth opportunities that exist in our markets and during the period continued to focus on residential, commercial and industrial customer conversions to natural gas and power generation gas delivery service opportunities. As we seek to expand the use of natural gas, we continue to emphasize natural gas as the fuel of choice for energy consumers because of the comfort, affordability, efficiency and environmental benefits of natural gas, as well as remind our customers of our reliability and safety as a company.

Customer additions in our residential and commercial markets increased for the quarter compared to the same period in 2011 by 22% and 10%, respectively. Residential gains were driven primarily by growth in our residential new construction and conversion markets where building permits increased modestly and lower wholesale natural gas costs continued to favorably position natural gas relative to other energy sources. Increased commercial growth reflected improvements in both commercial new construction activity and commercial conversion opportunities. We continue to forecast gross customer addition growth for fiscal 2012 of approximately 1%.

We completed a pipeline expansion project in December 2011 to provide long-term gas transportation service to a power generation customer in our market area. We have two pipeline expansion projects under construction to provide natural gas delivery service to power generation facilities currently under construction in North Carolina with targeted in service dates of June 2012 and June 2013. In addition to the environmental benefits of replacing coal-fired power plants with new efficient, combined-cycle natural gas-fired power plants, the construction of the natural gas pipelines for these projects will also add to our natural gas infrastructure in the eastern part of North Carolina and enhance future opportunities for economic growth and development. See the following discussion of our forecasted capital investment related to the construction of the natural gas pipelines and compressor stations to serve these new power generation facilities in "Cash Flows from Investing Activities" in Item 2 of this Form 10-Q in Management's Discussion and Analysis of Financial Condition and Results of Operations.

We see opportunity in the clean energy technology of compressed natural gas (CNG) vehicles. We are executing a plan to build more CNG fueling stations in our service area for use by our own vehicle fleet as well as by customers. Currently, approximately 11% of our vehicle fleet uses CNG. We have five company CNG fueling stations in use, and we plan to construct up to five more in fiscal year 2012. Within two years, we anticipate that up to 33% of our fleet may be capable of using CNG. We are also actively pursuing other commercial fleets to utilize company CNG stations and have had discussions with commercial customers for fueling stations at customer sites with sufficient usage.

We continue our regulatory strategy to align our rate structures between shareholder and customer interests. Notably, on January 23, 2012, the TRA approved a settlement agreement between us and the Consumer Advocate and Protection Division that resolved all issues in the general rate proceeding, including an increase in rates and charges to all customers of $11.9 million annually, effective March 1, 2012. As part of the settlement, we have shifted more of our cost recovery to the fixed portion of the customers' bills to somewhat mitigate volumetric charges. Also approved was an expansion of the WNA period to October through April with updated WNA factors and the recovery of various deferred regulatory assets. For further information, see Note 2 to the consolidated financial statements.

To support our strategic objectives focusing on excellence in customer service, as discussed above in the "Overview," during the period we reorganized our field customer services, sales and marketing, field operations and maintenance and construction departments into functional organizations to provide a more focused and better managed approach to customer service with an end goal of increasing customer loyalty and satisfaction while improving operational efficiencies. We have also implemented new centralized service scheduling work processes and system enhancements to better serve our customers in a more timely and efficient fashion.

In order to fund our capital expansion projects as well as our ongoing capital needs, we have continued to focus on securing funds at the lowest cost to us to provide for operations and capital investments. On February 15, 2012, we secured pricing confirmations from lenders that price $300 million of private placement long-term debt with the intention to issue $100 million in July 2012 and the remaining $200 million in October 2012. In March 2012, we initiated a commercial paper program (CP program) that is backstopped by our syndicated revolving credit facility for a combined borrowing capacity of $650 million. We anticipate interest expense savings of $2.5 million annually due to the lower interest rates associated with the sale of commercial paper compared to drawing on our syndicated revolving credit facility. The short-term notes under the CP program will not be registered under the Securities Act of 1933 for public offering and may not be offered or sold by us absent registration or exemption from registration requirements. We will be issuing the notes pursuant to an exemption from registration. We also have an open shelf registration filed in June 2011 with the SEC that is available for future issuances of debt or equity.

The Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, enacted in December 2010, extended the 50% "bonus depreciation" that expired December 31, 2009 and temporarily increased "bonus depreciation" for federal income tax purposes to 100% for certain qualified investments. These provisions are effective for our fiscal year tax returns for 2010-2014. The Internal Revenue Service has issued regulations that are intended to provide guidance in interpreting the law. Based on current capital projections and timelines, we are anticipating a benefit through 2014 of $130-170 million. We anticipate that the bonus depreciation allowance will have a material favorable impact on our cash flows in the near term by reducing cash needed to pay federal income taxes.

Our first quarter in 2012 reflected a warmer-than-normal start to the 2011-2012 winter heating season. The weather in our first quarter was 16% warmer than normal and 31% warmer than the first quarter of 2011. During the three months ended January 31, 2012, net income decreased $8.2 million as compared with the prior year period primarily due to the following:

- Margin decreased $9.8 million from several factors, primarily influenced by weather. Margin from secondary wholesale market sales decreased $5.5 million due to less transactional opportunities because of lower natural gas demand and less volatility in wholesale natural gas pricing. Residential and commercial retail margin decreased $4.3 million primarily from decreased sales of 16.9 million dekatherms. The majority of the margin decrease is attributable to our residential and commercial customer classes in South Carolina and Tennessee where our rates are not fully decoupled and WNA does not perfectly adjust for variances in warmer- or colder-than-normal weather. Margin from the sales to and transport of gas for our industrial and resale customers decreased $1.1 million primarily because of warmer weather, partially offset by an increase in margin of $.8 million from power generation customers.
- Operations and maintenance expenses increased $7.3 million due to higher pension expense, including the absence of a regulatory pension deferral in 2012, increased medical coverage expense, contract labor expenses related to process improvement efforts and payroll.

Additional information on operating results for the quarter follows.

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Results of Operations

We reported net income of $76.2 million for the three months ended January 31, 2012 as compared to $84.4 million for the same period in 2011. The following table sets forth a comparison of the components of our consolidated statements of comprehensive income for the three months ended January 31, 2012 as compared with the three months ended January 31, 2011.

Comprehensive Income Statement Components

In thousands, except per share amounts	Three Months Ended January 31 2012	Three Months Ended January 31 2011	Variance	Percent Change
Operating Revenues	$ 471,840	$ 652,056	$ (180,216)	(27.6)%
Cost of Gas	251,603	422,050	(170,447)	(40.4)%
Margin	220,237	230,006	(9,769)	(4.2)%
Operations and Maintenance	58,397	51,058	7,339	14.4 %
Depreciation	26,178	25,047	1,131	4.5 %
General Taxes	8,622	11,097	(2,475)	(22.3)%
Utility Income Taxes	47,221	51,935	(4,714)	(9.1)%
Total Operating Expenses	140,418	139,137	1,281	0.9 %
Operating Income	79,819	90,869	(11,050)	(12.2)%
Other Income (Expense), net of tax	3,614	4,588	(974)	(21.2)%
Utility Interest Charges	7,206	11,017	(3,811)	(34.6)%
Net Income	$ 76,227	$ 84,440	$ (8,213)	(9.7)%
Average Shares of Common Stock:				
Basic	72,126	72,194	(68)	(0.1)%
Diluted	72,433	72,514	(81)	(0.1)%
Earnings Per Share of Common Stock:				
Basic	$ 1.06	$ 1.17	$ (0.11)	(9.4)%
Diluted	$ 1.05	$ 1.16	$ (0.11)	(9.5)%

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Key statistics are shown in the table below for the three months ended January 31, 2012 and 2011.

Gas Deliveries, Customers, Weather Statistics and Number of Employees

	Three Months Ended January 31			
	2012	2011	Variance	Percent Change
Deliveries in Dekatherms (in thousands):				
Sales Volumes	38,596	56,177	(17,581)	(31.3)%
Transportation Volumes	51,632	41,667	9,965	23.9%
Throughput	90,228	97,844	(7,616)	(7.8)%
Secondary Market Volumes	11,447	14,286	(2,839)	(19.9)%
Customers Billed (at period end)	983,481	979,728	3,753	0.4%
Gross Customer Additions	3,438	2,857	581	20.3%
Degree Days				
Actual	1,568	2,278	(710)	(31.2)%
Normal	1,869	1,865	4	0.2%
Percent (warmer) colder than normal	(16.1)%	22.1%	n/a	n/a
Number of Employees (at period end)	1,782	1,774	8	0.5%

Operating Revenues

Operating revenues decreased $180.2 million for the three months ended January 31, 2012 compared with the same period in 2011 primarily due to the following decreases:

- $186.7 million of lower gas costs passed through to sales customers.
- $54.2 million from lower revenues in secondary market transactions due to decreased activity and margins.

These decreases were partially offset by the following increases:

- $44.7 million from increased revenues under the margin decoupling mechanism.
- $13.6 million from increased revenues under the WNA in South Carolina and Tennessee.
- $1.9 million from increased volumes delivered to transportation customers, including new power generation customers.

Cost of Gas

Cost of gas decreased $170.4 million for the three months ended January 31, 2012 compared with the same period in 2011 primarily due to the following decreases:

- $140.7 million of decreased commodity gas costs primarily from lower volumes sold and lower gas costs passed through to sales customers.
- $48.7 million of decreased commodity gas costs in secondary marketing transactions due to decreased activity and lower average gas costs.
- $4.1 million of decreased pipeline demand charges primarily due to changing asset manager payments.

These decreases were partially offset by $23.3 million of increased costs due to regulatory approved gas cost mechanisms.

In all three states, we are authorized to recover from customers all prudently incurred gas costs. Charges to cost of gas are based on the amount recoverable under approved rate schedules. The net of any over- or under-recoveries of gas costs are reflected in a regulatory deferred account and are added to or deducted from cost of gas and are included in "Amounts due from customers" or "Amounts due to customers" in the consolidated balance sheets.

Margin

Margin decreased $9.8 million for the three months ended January 31, 2012 compared with the same period in 2011 primarily due to the following decreases:

- $5.5 million in decreased secondary market activity and margins due to decreased activity resulting from warmer weather and less wholesale natural gas price volatility.
- $4.3 million primarily due to decreases in sales to residential and commercial classes because of warmer weather in jurisdictions where our rates are not fully decoupled and WNA does not perfectly adjust for variances from normal weather, slightly offset by residential customer growth.

Our utility margin is defined as natural gas revenues less natural gas commodity purchases and fixed gas costs for transportation and storage capacity. Margin, rather than revenues, is used by management to evaluate utility operations due to the passthrough of changes in wholesale commodity gas costs, which accounted for 37% of revenues for the three months ended January 31, 2012, and transportation and storage costs, which accounted for 7%.

In general rate proceedings, state regulatory commissions authorize us to recover a margin, which is the applicable billing rate less cost of gas, on each unit of gas delivered. The commissions also authorize us to recover margin losses resulting from negotiating lower rates to industrial customers when necessary to remain competitive. The ability to recover such negotiated margin reductions is subject to continuing regulatory approvals.

Our utility margin is also impacted by certain regulatory mechanisms as defined elsewhere in this document and in our Form 10-K for the year ended October 31, 2011. These include WNA in Tennessee and South Carolina, the Natural Gas Rate Stabilization Act in South Carolina, secondary market activity in North Carolina and South Carolina, Tennessee Incentive Plan in Tennessee, the margin decoupling mechanism in North Carolina and negotiated loss treatment and the recovery of uncollectible gas costs in all three jurisdictions. We retain 25% of secondary market margins generated through off-system sales and capacity release activity in all jurisdictions, with 75% credited to customers through the incentive plans.

Operations and Maintenance Expenses

Operations and maintenance expenses increased $7.3 million for the three months ended January 31, 2012 compared with the same period in 2011 primarily due to the following increases:

- $4.2 million in higher pension expense, including the absence of a regulatory pension deferral in 2012, and increased medical coverage expense.
- $1.1 million in contract labor expenses for process improvement efforts.
- $.8 million in higher payroll.
- $.7 million in materials primarily due to increased usage.

Depreciation

Depreciation expense increased $1.1 million for the three months ended January 31, 2012 compared with the same period in 2011 primarily due to increases in plant in service.

General Taxes

General taxes decreased $2.5 million for the three months ended January 31, 2012 compared with the same period in 2011 primarily due to the accrual of a liability in 2011 for sales tax on certain customer accounts that were not exempt from sales tax.

Other Income (Expense)

Other Income (Expense) is comprised of income from equity method investments, non-operating income, non-operating expense and income taxes related to these items. Non-operating income includes non-regulated merchandising and service work, home service warranty programs, subsidiary operations, interest income and other miscellaneous income. Non-operating expense is comprised of charitable contributions and other miscellaneous expenses.

The primary change to Other Income (Expense) for the three months ended January 31, 2012 compared with the same period in 2011 was in income from equity method investments. All other changes were insignificant for the period.

Income from equity method investments decreased $1.5 million for the three months ended January 31, 2012 compared with the same period in 2011 due to a $1.6 million decrease in earnings from SouthStar Energy Services LLC primarily due to lower customer usage related to warmer weather and the recording of a lower of cost or market storage inventory adjustment in the current year period as compared with the prior year period, partially offset by higher retail price spreads and lower transportation and gas costs.

Utility Interest Charges

Utility interest charges decreased $3.8 million for the three months ended January 31, 2012 compared with the same period in 2011 primarily due to the following changes:

- $2.1 million decrease in interest expense due to an increase in capitalized interest in the borrowed allowance for funds used during construction primarily due to increased construction expenditures.
- $2.1 million decrease in interest expense on long-term debt primarily due to lower amounts of debt outstanding at lower interest rates.
- $.8 million increase in interest expense on short-term debt primarily due to higher balances outstanding during the current period at average interest rates that were approximately 60 basis points higher in the current period.

Financial Condition and Liquidity

To meet our capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, access to capital markets, cash generated from our investments in joint ventures and short-term bank borrowings. Our capital market strategy has continued to focus on maintaining a strong balance sheet, ensuring sufficient cash resources and daily liquidity, accessing capital markets at favorable times when needed, managing critical business risks, and maintaining a balanced capital structure through the issuance of equity or long-term debt securities or the repurchase of our equity securities.

We believe the capacity of short-term credit available to us under our revolving syndicated credit facility and the issuance of debt and equity securities, together with cash provided by operating activities, will continue to allow us to meet our needs for working capital, construction expenditures, investments in joint ventures, anticipated debt redemptions, dividend payments, employee benefit plan contributions, common share repurchases and other cash needs.

Short-Term Borrowings. We have a $650 million three-year revolving syndicated credit facility. The facility expires in January 2014 and has an option to expand up to $850 million. We pay an annual fee of $30,000 plus fifteen basis points for any unused amount up to $650 million. During the three months ended January 31, 2012, short-term bank borrowings ranged from $328.5 million to $475.5 million, and interest rates ranged from 1.15% to 1.20%.

In March 2012, we established a $650 million unsecured CP program. The notes issued under the CP program will have maturities not to exceed 397 days from the date of issuance and will be backstopped by our existing $650 million revolving syndicated credit facility expiring January 25, 2014. The amount outstanding under the revolving syndicated credit facility and the CP program, either individually or in the aggregate, cannot exceed $650 million. Any borrowings under the CP program will rank equally with our other unsubordinated and unsecured debt. Due to lower interest rates associated with commercial paper as opposed to drawing on our revolving syndicated credit facility, we anticipate annual saving of approximately $2.5 million. The short-term notes under the CP program will not be registered under the Securities Act of 1933 for public offering and may not be offered or sold by us absent registration or exemption from registration requirements. We will be issuing the notes pursuant to an exemption from registration.

Our short-term borrowings at quarter end consisting only of the revolving syndicated credit facility, as included in "Bank Debt" in the consolidated balance sheets, are vital in order to meet working capital needs, such as our seasonal requirements for gas supply, general corporate liquidity, capital expenditures and approved investments. We rely on short-term borrowings together with long-term capital markets to provide a significant source of liquidity to meet operating requirements that are not satisfied by internally generated cash flows. Currently, cash flows from operations are not adequate to finance the full cost of planned capital expenditures, which are fundamental to support our system infrastructure and the growth in our customer base. We believe that our revolving syndicated credit facility, along with our access to capital markets, will allow us to meet the increased capital requirements anticipated to be spent over the next two years.

Highlights for our bank borrowings as of January 31, 2012 and for the quarter ended January 31, 2012 are presented below.

Bank Borrowings
As of January 31, 2012

In thousands		
End of period (January 31, 2012):		
Amount outstanding	$	457,500
Weighted average interest rate		1.17%
During the period (November 1, 2011 - January 31, 2012):		
Average amount outstanding	$	393,900
Weighted average interest rate		1.18%
Maximum amount outstanding:		
November	$	380,500
December		399,000
January		475,500

On January 1, 2012, we made interest payments of $14.7 million on long-term debt; these payments were made using cash from operations that reduced the maximum amount outstanding in January to a lower balance outstanding at month end.

The level of short-term bank borrowings can vary significantly due to changes in the wholesale cost of natural gas and the level of purchases of natural gas supplies for storage to serve customer demand. We pay our suppliers for natural gas purchases before we collect our costs from customers through their monthly bills. If wholesale gas prices increase, we may incur more short-term debt for natural gas inventory and other operating costs since collections from customers could be slower and some customers may not be able to pay their gas bills on a timely basis.

As of January 31, 2012, we had $10 million available for letters of credit under our revolving syndicated credit facility, of which $2.9 million were issued and outstanding. The letters of credit are used to guarantee claims from self-insurance under our general and automobile liability policies. As of January 31, 2012, unused lines of credit available under our revolving syndicated credit facility, including the issuance of the letters of credit, totaled $189.6 million.

Cash Flows from Operating Activities. The natural gas business is seasonal in nature. Operating cash flows may fluctuate significantly during the year and from year to year due to working capital changes within our utility and non-utility operations. The major factors that affect our working capital are weather, natural gas purchases and prices, natural gas storage activity, collections from customers and deferred gas cost recoveries. We rely on operating cash flows and short-term bank borrowings to meet seasonal working capital needs. During our first and second quarters, we generally experience overall positive cash flows from the sale of flowing gas and gas withdrawal from storage and the collection of amounts billed to customers during the November through March winter heating season. Cash requirements generally increase during the third and fourth quarters due to increases in natural gas purchases injected into storage, construction activity and decreases in receipts from customers.

During the winter heating season, our trade accounts payable increase to reflect amounts due to our natural gas suppliers for commodity and pipeline capacity. The cost of the natural gas can vary significantly from period to period due to changes in the price of natural gas, which is a function of market fluctuations in the commodity cost of natural gas, along with our changing requirements for storage volumes. Differences between natural gas costs that we have paid to suppliers and amounts that we have collected from customers are included in regulatory deferred accounts in amounts due to or from customers. These natural gas costs can cause cash flows to vary significantly from period to period along with variations in the timing of collections from customers under our gas cost recovery mechanisms.

Cash flows from operations are impacted by weather, which affects gas purchases and sales. Warmer weather can lead to lower revenues from fewer volumes of natural gas sold or transported. Colder weather can increase volumes sold to weather-sensitive customers, but may lead to conservation by customers in order to reduce their heating bills. Warmer-than-normal weather can lead to reduced operating cash flows, thereby increasing the need for short-term bank borrowings to meet current cash requirements.

Because of the weak economy, including continued high unemployment, we may incur additional bad debt expense as well as experience increased customer conservation. We may incur more short-term debt to pay for gas supplies and other operating costs since collections from customers could be slower and some customers may not be able to pay their bills. Regulatory margin stabilizing and cost recovery mechanisms, such as those that allow us to recover the gas cost portion of bad debt expense, are expected to mitigate the impact these factors may have on our results of operations.

Net cash provided by operating activities was $24.6 million and $21.2 million for the three months ended January 31, 2012 and 2011, respectively. Net cash provided by operating activities reflects a decrease of $8.2 million in net income for 2012 compared with 2011 primarily due to lower margin earned in 2012 as well as higher operating costs. The effect of changes in working capital on net cash provided by operating activities is described below:

- Trade accounts receivable and unbilled utility revenues increased $157.6 million from October 31, 2011 primarily due to the winter consumption of gas and decreased $116.1 million compared with January 31, 2011 primarily due to 31.2% warmer weather during the current period than the same prior period. Volumes sold to weather-sensitive residential and commercial customers decreased 16.9 million dekatherms as compared with the same prior period. Total throughput decreased 7.6 million dekatherms as compared with the same prior period, largely from decreased sales to residential, commercial and industrial customers, partially offset by increased volumes of 11.6 million dekatherms, or 79%, sold to and transported for power generation customers.
- Net amounts due from customers decreased $10.4 million from October 31, 2011 primarily due to the collection of deferred gas costs through rates.
- Gas in storage increased $14.2 million in the current period primarily due to increased volumes of gas in storage from lower customer sales, partially offset by a decrease in the weighted average cost of gas purchased for injections in 2012 as compared with the prior year.
- Prepaid gas costs decreased $35.8 million in the current period primarily due to gas being made available for sale during the period. Under some gas supply contracts, prepaid gas costs incurred during the summer months represent purchases of gas that are not available for sale, and therefore not recorded in inventory, until the start of the winter heating season.
- Trade accounts payable increased $30.3 million in the current period primarily due to increased gas purchases to meet greater customer demand during the winter months.

Our three state regulatory commissions approve rates that are designed to give us the opportunity to generate revenues to cover our gas costs, fixed and variable non-gas costs and earn a fair return for our shareholders. We have a WNA mechanism in South Carolina and Tennessee that partially offsets the impact of colder- or warmer-than-normal weather on bills rendered in November through March for residential and commercial customers. The WNA in South Carolina and Tennessee generated charges to customers of $7.1 million and credits of $6.5 million in the three months ended January 31, 2012 and 2011, respectively. In Tennessee, adjustments are made directly to individual customer bills. In South Carolina, the adjustments are calculated at the individual customer level but are recorded in "Amounts due from customers" or "Amounts due to customers" in the consolidated balance sheets for subsequent collection from or refund to all customers in the class. The margin decoupling mechanism in North Carolina provides for the collection of our approved margin from residential and commercial customers independent of consumption patterns. The margin decoupling mechanism increased margin by $16.8 million and decreased margin by $27.9 million in the three months ended January 31, 2012 and 2011, respectively. Our gas costs are recoverable through PGA procedures and are not affected by the WNA or the margin decoupling mechanism.

The financial condition of the natural gas marketers and pipelines that supply and deliver natural gas to our distribution system can increase our exposure to supply and price fluctuations. We believe our risk exposure to the financial condition of the marketers and pipelines is not significant based on our receipt of the products and services prior to payment and the availability of other marketers of natural gas to meet our firm supply needs if necessary. We have regulatory commission approval in North Carolina, South Carolina and Tennessee that places tighter credit requirements on the retail natural gas marketers that schedule gas for transportation service on our system.

The regulated utility competes with other energy products, such as electricity and propane, in the residential and commercial customer markets. The most significant product competition is with electricity for space heating, water heating and cooking. Numerous factors can influence customer demand for natural gas, including price, value, availability, environmental attributes, reliability and energy efficiency. Increases in the price of natural gas can negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This can impact our cash needs if customer growth slows, resulting in reduced capital expenditures, or if customers conserve, resulting in reduced gas purchases and customer billings.

In the industrial market, many of our customers are capable of burning a fuel other than natural gas, with fuel oil being the most significant competing energy alternative. Our ability to maintain industrial market share is largely dependent on price. The relationship between supply and demand has the greatest impact on the price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between worldwide supply and demand and the policies of foreign and domestic governments and organizations, as well as the value of the US dollar versus other currencies. Our liquidity could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

In an effort to keep customer rates competitive and to maximize earnings, we continue to implement business process improvement and operations and maintenance cost management programs to capture operational efficiencies while improving customer service and maintaining a safe and reliable system.

Cash Flows from Investing Activities. Net cash used in investing activities was $104.6 million and $40.4 million for the three months ended January 31, 2012 and 2011, respectively. Net cash used in investing activities was primarily for utility construction expenditures. Gross utility construction expenditures for the three months ended January 31, 2012 were $98.1 million as compared to $38.2 million in the same prior period primarily due to expending $51 million for the construction of power generation service delivery projects in 2012 as compared with $11.5 million expended for these projects in the same prior period.

We have a substantial capital expansion program for the construction of transmission and distribution facilities, purchase of equipment and other general improvements. This program primarily supports our system infrastructure and the growth in our customer base. Significant utility construction expenditures are expected to meet long-term growth, including the power generation market, and are part of our long-range forecasts that are prepared at least annually and typically cover a forecast period of five years. We are contractually obligated to expend capital as the work is completed.

We anticipate making capital expenditures, including allowance for funds used during construction, of $260 - 280 million and $90 - 100 million in our fiscal years 2012 and 2013, respectively, to provide natural gas service for two new power generation facilities in North Carolina. These expenditures are significantly higher than we have traditionally expended for service expansions. We intend to fund expenditures related to these projects in a manner that maintains our targeted capitalization ratio of 45-50% in long-term debt and 50-55% in common equity. Additional detail for the anticipated capital expenditures follows.

In millions	2012	2013	2014
Utility capital expenditures	$ 280 - 320	$ 290 - 320	$ 200 - 250
Power generation related capital expenditures	260 - 280	90 - 100	—
Total forecasted capital expenditures	$ 540 - 600	$ 380 - 420	$ 200 - 250

In October 2009, we reached an agreement with Progress Energy Carolinas to provide natural gas delivery service to a power generation facility to be built at their Wayne County, North Carolina site. The agreement, approved by the NCUC in May 2010, calls for us to construct approximately 38 miles of 20-inch transmission pipeline along with compression facilities to provide natural gas delivery service to the plant by June 2012. We began construction in February 2010. Our investment in the pipeline and compression facilities is supported by a long-term service agreement. To provide the additional delivery service, we have executed an agreement with Cardinal Pipeline Company, L.L.C. (Cardinal) to expand our firm capacity requirement by 149,000 dekatherms per day to serve this facility. This will require Cardinal to spend an estimated $48 million to expand its system. As a 21.49% equity venture partner of Cardinal, we will invest an estimated $10.3 million in Cardinal's system expansion. Capital contributions related to this system expansion began in January 2011 and will continue on a periodic basis through September 2012. As of January 31, 2012, our contributions to date related to this system expansion were $8 million. For further information regarding this agreement, see Note 11 to the consolidated financial statements.

In April 2010, we reached another agreement with Progress Energy Carolinas to provide natural gas delivery service to a power generation facility to be built at their existing Sutton site near Wilmington, North Carolina. The agreement, also approved by the NCUC in May 2010, calls for us to construct approximately 130 miles of transmission pipeline along with compression facilities to provide natural gas delivery service to the plant by June 2013. We began construction in May 2010. Our service to Progress Energy Carolinas is supported by a long-term service agreement. We anticipate that a portion of the cost of this project will be included in our North Carolina utility rate base because the facilities will enhance our ability to serve our other North Carolina customers.

The Sutton facilities will create cost effective expansion capacity that we will use to help serve the growing natural gas requirements of our customers in the eastern part of North Carolina. At the present time with the timing and design scope of the Sutton facilities, there is no current need to proceed with our previously announced Robeson liquefied natural gas storage project. The timing and design scope of the expansion of our facilities in Robeson County will be determined as our system infrastructure and market supply growth requirements in North Carolina dictate.

In December 2011 under an agreement with Duke Energy Carolinas, we placed into service the natural gas pipeline facilities that we constructed to provide natural gas delivery service to their Rockingham County, North Carolina power generation facility.

Cash Flows from Financing Activities. Net cash provided by financing activities was $83.3 million and $33.6 million for the three months ended January 31, 2012 and 2011, respectively. Funds are primarily provided from bank borrowings and the issuance of common stock through our dividend reinvestment and stock purchase plan (DRIP) and our employee stock purchase plan (ESPP). We may sell common stock and long-term debt when market and other conditions favor such long-term financing. Funds are primarily used to retire long-term debt, pay down outstanding short-term bank borrowings, repurchase common stock under the common stock repurchase program and pay quarterly dividends on our common stock.

Outstanding short-term bank borrowings increased from $331 million as of October 31, 2011 to $457.5 million as of January 31, 2012 primarily due to higher capital expenditures and to increased gas purchases to meet greater customer demand during the winter months. For further information on bank borrowings, see the previous discussion of "Short-Term Borrowings" in "Financial Condition and Liquidity."

We have an open combined debt and equity shelf registration filed in July 2011 that is available for future use. Unless otherwise specified at the time such securities are offered for sale, the net proceeds from the sale of the securities will be used for general corporate purposes, including capital expenditures, additions to working capital and advances for our investments in our subsidiaries, and for repurchases of shares of our common stock. Pending such use, we may temporarily invest any net proceeds that are not applied to the purposes mentioned above in investment grade securities.

On March 1, 2012, we established a $650 million unsecured CP program. For further information on our CP program, see the previous discussion of "Short-Term Borrowings" in "Financial Condition and Liquidity."

We continually monitor customer growth trends, opportunities in our markets, the economic recovery of our service area and the timing of any infrastructure investments that would require the need for additional long-term debt. In February 2012, we secured pricing confirmations from lenders that price $300 million of private placement long-term debt with the transaction expected to close in March 2012. We will be issuing $100 million on or around July 16, 2012 with an interest rate of 3.47%. On or around October 15, 2012, we will be issuing the remaining $200 million with an interest rate of 3.57%. The proceeds will be used for general corporate purposes, including the funding of capital expenditures for power generation gas delivery service projects.

During the three months ended January 31, 2012 and 2011, we issued $4.9 million and $4.8 million, respectively, of common stock through DRIP and ESPP. From time to time, we have repurchased shares of common stock under our Common Stock Open Market Purchase Program as described in Part II, Item 2 in this Form 10-Q. During the three months ended January 31, 2012, we repurchased and retired .8 million shares for $27 million, leaving a balance of 2,910,074 shares available for repurchase under the program. This transaction settled on February 28, 2012, and we received $.5 million from the investment bank. During the three months ended January 31, 2011, we repurchased and retired .8 million shares for $22.2 million under the program that settled in our second quarter in 2011.

We have paid quarterly dividends on our common stock since 1956. Provisions contained in certain note agreements under which long-term debt was issued restrict the amount of cash dividends that may be paid. As of January 31, 2012, our retained earnings were not restricted. On March 8, 2012, the Board of Directors declared a quarterly dividend on common stock of $.30 per share, payable April 13, 2012 to shareholders of record at the close of business on March 23, 2012.

Our long-term targeted capitalization ratio is 45-50% in long-term debt and 50-55% in common equity. As of January 31, 2012, our capitalization, including current maturities of long-term debt, if any, consisted of 40% in long-term debt and 60% in common equity.

The components of our total debt outstanding (short-term debt and long-term debt) to our total capitalization as of January 31, 2012 and 2011, and October 31, 2011, are summarized in the table below.

	January 31		October 31		January 31	
In thousands	2012	Percentage	2011	Percentage	2011	Percentage
Short-term debt	$ 457,500	21%	$ 331,000	16%	$ 315,500	15%
Current portion of long-term debt	—	—%	—	—%	60,000	3%
Long-term debt	675,000	31%	675,000	34%	671,904	33%
Total debt	1,132,500	52%	1,006,000	50%	1,047,404	51%
Common stockholders' equity	1,030,086	48%	996,923	50%	1,015,514	49%
Total capitalization (including short-term debt)	$ 2,162,586	100%	$ 2,002,923	100%	$ 2,062,918	100%

Credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financings. We believe our credit ratings will allow us to continue to have access to the capital markets, as and when needed, at a reasonable cost of funds. In determining our credit ratings, the rating agencies consider a number of quantitative and qualitative factors. For a listing of the more significant quantitative and qualitative factors considered by the rating agencies, see "Cash Flows from Financing Activities" in Management's Discussion and Analysis of Financial Condition and Results of Operations in our Form 10-K for the year ended October 31, 2011.

As of January 31, 2012, all of our long-term debt was unsecured. Our long-term debt is rated "A" by Standard & Poor's Ratings Services and "A3" by Moody's Investors Service. Currently, with respect to our long-term debt, the credit agencies maintain their stable outlook. Credit ratings and outlooks are opinions of the rating agency and are subject to their ongoing review. A significant decline in our operating performance, capital structure or a significant reduction in our liquidity could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by our rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn by a rating agency if, in its judgment, circumstances warrant a change.

We are subject to default provisions related to our long-term debt and short-term borrowings. Failure to satisfy any of the default provisions may result in total outstanding issues of debt becoming due. There are cross-default provisions in all of our debt agreements. As of January 31, 2012, there has been no event of default giving rise to acceleration of our debt.

Estimated Future Contractual Obligations

During the three months ended January 31, 2012, there were no material changes to our estimated future contractual obligations in Management's Discussion and Analysis in this Form 10-Q compared to what we disclosed in our Form 10-K for the year ended October 31, 2011.

Off-balance Sheet Arrangements

We have no off-balance sheet arrangements other than letters of credit, an open accelerated share repurchase (ASR) agreement and operating leases. The letters of credit and the ASR are discussed in Note 4 and Note 5, respectively, to the consolidated financial statements in this Form 10-Q. The operating leases were discussed in Note 8 to the consolidated financial statements in our Form 10-K for the year ended October 31, 2011.

Critical Accounting Policies and Estimates

We prepare the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. We make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results may differ significantly from these estimates and assumptions. We base our estimates on historical experience, where applicable, and other relevant factors that we believe are reasonable under the circumstances. On an ongoing basis, we evaluate estimates and assumptions and make adjustments in subsequent periods to reflect more current information if we determine that modifications in assumptions and estimates are warranted.

Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made, and changes in the estimate or a different estimate that could have been used would have had a material impact on our financial condition or results of operations. We consider regulatory accounting, revenue recognition, and pension and postretirement benefits to be our critical accounting estimates. Management is responsible for the selection of these critical accounting estimates presented in our Form 10-K for the year ended October 31, 2011 in Management's Discussion and Analysis of Financial Condition and Results of Operations. Management has discussed these critical accounting estimates with the Audit Committee of the Board of Directors. There have been no changes in our critical accounting policies and estimates since October 31, 2011.

Accounting Guidance

For information regarding recently issued accounting guidance, see Note 1 to the consolidated financial statements in this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to various forms of market risk, including the credit risk of our suppliers and our customers, interest rate risk, commodity price risk and weather risk. We seek to identify, assess, monitor and manage all of these risks in accordance with defined policies and procedures under an Enterprise Risk Management program and with the direction of the Energy Price Risk Management Committee. Risk management is guided by senior management with Board of Directors' oversight, and senior management takes an active role in the development of policies and procedures.

During the three months ended January 31, 2012, there were no material changes in the way that we monitor and manage market risk and credit risk in accordance with our policies and procedures. Our exposure to and management of interest rate risk, commodity price risk and weather risk has remained the same during the three months ended January 31, 2012. Our annual discussion of market risk was included in Item 7A of our Form 10-K as of October 31, 2011.

Additional information concerning market risk is included in "Financial Condition and Liquidity" in Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 2 in this Form 10-Q.

As of January 31, 2012, we had $457.5 million of short-term debt outstanding under our revolving syndicated credit facility at an interest rate of 1.17%. The carrying amount of our short-term debt approximates fair value. A change of 100 basis points in the underlying average interest rate for our short-term debt would have caused a change in interest expense of approximately $1 million during the three months ended January 31, 2012.

Item 4. Controls and Procedures

Our management, including the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as defined in Rules

13a-15(e) and 15d-15(e) under the Exchange Act as of the end of the period covered by this Form 10-Q. Such disclosure controls and procedures are designed to provide reasonable assurance that the information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods required by the United States Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based on such evaluation, the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer concluded that, as of the end of the period covered by this Form 10-Q, our disclosure controls and procedures were effective at the reasonable assurance level.

We routinely review our internal control over financial reporting and from time to time make changes intended to enhance the effectiveness of our internal control over financial reporting. There were no changes to our internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act during the first quarter of fiscal 2012 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

We have only routine immaterial litigation in the normal course of business.

Item 1A. Risk Factors

During the three months ended January 31, 2012, there were no material changes to our risk factors that were disclosed in our Form 10-K for the year ended October 31, 2011.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

a) Sale of Unregistered Equity Securities.

None.

c) Issuer Purchases of Equity Securities.

The following table provides information with respect to repurchases of our common stock under the Common Stock Open Market Purchase Program during the three months ended January 31, 2012.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program (1)
Beginning of the period				3,710,074
11/1/11 - 11/30/11	—	$—	—	3,710,074
12/1/11 - 12/31/11	—	$—	—	3,710,074
1/1/12 - 1/31/12	800,000	$33.77	800,000	2,910,074
Total	800,000	$33.77	800,000	

(1) The Common Stock Open Market Purchase Program was approved by the Board of Directors and announced on June 4, 2004 to purchase up to three million shares of common stock for reissuance under our dividend reinvestment and stock purchase, employee stock purchase and incentive compensation plans. On December 16, 2005, the Board of Directors approved an increase in the number of shares in this program from three million to six million to reflect the two-for-one stock split in 2004. The Board also approved on that date an amendment of the Common Stock Open Market Purchase Program to provide for the purchase of up to four million additional shares of common stock to maintain our debt-to-equity capitalization ratios at target levels. The additional four million shares were referred to as our accelerated share repurchase (ASR) program. On March 6, 2009, the Board of Directors authorized the repurchase of up to an additional four million shares under the Common Stock Open Market Purchase Program and the ASR program, which were consolidated.

The amount of cash dividends that may be paid on common stock is restricted by provisions contained in certain note agreements under which long-term debt was issued, with those for the senior notes being the most restrictive. We cannot pay or declare any dividends or make any other distribution on any class of stock or make any investments in subsidiaries or permit any subsidiary to do any of the above (all of the foregoing being "restricted payments"), except out of net earnings available for restricted payments. As of January 31, 2012, net earnings available for restricted payments were greater than retained earnings; therefore, our retained earnings were not restricted.

Item 6. Exhibits

Compensatory Contracts:

10.1	Instrument of Amendment for Piedmont Natural Gas Company, Inc. Defined Contribution Restoration Plan dated as of January 23, 2012, by Piedmont Natural Gas Company, Inc.
10.2	2011 Retention Award Agreement dated December 15, 2011 between Piedmont Natural Gas Company, Inc. and Thomas E. Skains
31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer
31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer
32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer
101.INS	XBRL Instance Document (1)
101.SCH	XBRL Taxonomy Extension Schema (1)
101.CAL	XBRL Taxonomy Calculation Linkbase (1)
101.DEF	XBRL Taxonomy Definition Linkbase (1)
101.LAB	XBRL Taxonomy Extension Label Linkbase (1)
101.PRE	XBRL Taxonomy Extension Presentation Linkbase (1)

(1) Furnished, not filed.

Attached as Exhibit 101 to this Quarterly Report are the following documents formatted in extensible business reporting language (XBRL): (1) Document and Entity Information; (2) Consolidated Balance Sheets at January 31, 2012 and October 31, 2011; (3) Consolidated Statements of Comprehensive Income for the three months ended January 31, 2012 and 2011; (4) Consolidated Statements of Cash Flows for the three months ended January 31, 2012 and 2011; (5) Consolidated Statements of Stockholders' Equity for the three months ended January 31, 2012 and 2011; and (6) Notes to Consolidated Financial Statements.

Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed furnished, not filed as part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability. We also make available on our web site the Interactive Data Files submitted as Exhibit 101 to this Quarterly Report.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	Piedmont Natural Gas Company, Inc.
	(Registrant)
Date March 9, 2012	/s/ Karl W. Newlin
	Karl W. Newlin Senior Vice President and Chief Financial Officer (Principal Financial Officer)
Date March 9, 2012	/s/ Jose M. Simon
	Jose M. Simon Vice President and Controller (Principal Accounting Officer)

Piedmont Natural Gas Company, Inc.
Form 10-Q
For the Quarter Ended January 31, 2012

Exhibits

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Exhibit 10.1

INSTRUMENT OF AMENDMENT FOR

PIEDMONT NATURAL GAS COMPANY, INC.

DEFINED CONTRIBUTION RESTORATION PLAN

THIS INSTRUMENT OF AMENDMENT (this "Instrument") is made and entered into as of the 23rd day of January, 2012, by PIEDMONT NATURAL GAS COMPANY, INC., a North Carolina corporation (the "Company").

Statement of Purpose

The Company maintains the Piedmont Natural Gas Company, Inc. Defined Contribution Restoration Plan (the "Plan"). The Company desires to amend the Plan to change the definition of retirement. In Section 6.1 of the Plan the Company has reserved the right to amend the Plan in whole or in part at any time and has further directed that the Benefit Plan Committee (the "Committee") shall have the authority to adopt any non-substantive amendment.

NOW, THEREFORE, the Company, acting through the Committee, does hereby declare that the Plan is amended to read as follows:

1. Effective as January 1, 2010, Section 2.1(b)(19) is amended in its entirety to read as follows:

""Retirement" shall mean a Participant's Separation from Service on or after such Participant is eligible for early or normal retirement under the defined benefit pension plan sponsored by the Company or would have been so eligible if the Participant were eligible to participate in such plan."

2. Except as expressly or by necessary implication amended hereby, the Plan shall continue in full force and effect.

IN WITNESS WHEREOF, the Company has caused this Instrument to be executed as of the day and year first above written.

PIEDMONT NATURAL GAS COMPANY, INC.
By: /s/ Kevin M. O'Hara
Kevin M. O'Hara
Senior Vice President, Chief Administrative Officer

"Company"

Exhibit 10.2

Piedmont Natural Gas Company, Inc.

2011 Retention Award Agreement

This **2011 RETENTION AWARD AGREEMENT** (this "Agreement") is made and entered into this the 15th day of December, 2011, by and between **PIEDMONT NATURAL GAS COMPANY, INC.**, a North Carolina corporation (the "Company"), and **THOMAS E. SKAINS** (the "Participant") pursuant to the Piedmont Natural Gas Company, Inc. Incentive Compensation Plan, as amended and restated effective December 15, 2010 (the "Plan"). Capitalized terms used herein without definition have the meaning given in the Plan.

1. Award of Retention Stock Units. The Company hereby evidences and confirms its award to the Participant, effective as of the date hereof (the "Award Date"), of 64,700 Common Stock units. All Common Stock units awarded to the Participant under this Agreement are subject to the restrictions contained herein and are referred to as the "Retention Stock Units." This Agreement is subordinate to, and the terms and conditions of the Retention Stock Units awarded hereunder are subject to, the terms and conditions of the Plan, which are incorporated by reference into this Agreement. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the terms of the Plan shall govern.

2. RSU Account; Dividend Equivalent Units. The Retention Stock Units shall be credited to a bookkeeping account in the name of the Participant on the books and records of the Company (the "RSU Account"). Within thirty (30) days after the payment date of any cash dividend with respect to Shares of Common Stock of the Company, the Participant's RSU Account shall be credited with the number of additional Retention Stock Units determined by dividing (a) the product of the total number of Retention Stock Units credited to the Participant's RSU Account as of the record date for such dividend multiplied by the per share amount of the dividend by (b) the Fair Market Value of a Share of Common Stock on such record date.

3. Vesting of Retention Stock Units.

(a) Vesting Period. Subject to the Participant's continuous employment with the Company or a Subsidiary, and except as provided in Section 3(c) of this Agreement or Article X of the Plan, the "Vesting Period" shall commence on the Award Date and expire, and the Retention Stock Units credited to the RSU Account shall become vested, in accordance with the following schedule:

Vesting Date	Percentage of RSU Account Vested
December 15, 2014	20%
December 15, 2015	30%
December 15, 2016	50%

Except for transfers by will or by the laws of descent and distribution, the Retention Stock Units may not be sold, assigned, transferred, pledged, hypothecated or otherwise directly or indirectly encumbered or disposed of until the expiration of the Vesting Period with respect to such Retention Stock Units.

(b) Termination of Employment. Except as otherwise provided in the Plan, if the Participant's employment terminates for any reason during the Vesting Period, the unvested Retention Stock Units shall be forfeited and canceled as of the date of such termination.

(c) Committee Discretion. Notwithstanding anything contained in this Agreement to the contrary, the Committee, in its sole discretion, may accelerate the expiration date of the Vesting Period at such time and upon such terms and conditions as the Committee shall determine.

4. Receipt of Common Stock.

(a) Upon Vesting. The Company shall issue to the Participant one Share of Common Stock for each vested Retention Stock Unit awarded to the Participant within five (5) business days after the expiration of the Vesting Period and the vesting of such Retention Stock Unit.

(b) Cancellation of Retention Stock Units. The Retention Stock Units in respect of which Shares of Common Stock are issued pursuant to Section 4(a) of this Agreement shall be removed from the RSU Account and canceled upon the issuance of such Common Stock. In no event shall Shares of Common Stock be issued to the Participant, or to any person or entity claiming by or through the Participant, in respect of unvested Retention Stock Units.

5. Limitation of Rights. The Retention Stock Units do not confer upon the Participant, or the Participant's estate or Designated Beneficiary in the event of the Participant's death, any rights as a shareholder of the Company unless and until Shares of Common Stock are in fact issued to such person in respect of the Retention Stock Units. Nothing in this Award Agreement shall interfere with or limit in any way the right of the Company to terminate the Participant's service at any time, nor confer upon the Participant any right to continue in the service of the Company.

6. Payment and Withholding of Taxes. The Company shall deduct from any Shares otherwise distributable to the Participant that number of Shares having a value equal to the amount of any taxes required by law to be withheld from awards made under the Plan. In the event the total amount of taxes required to be withheld by law is less than 50% of the value of the Shares distributable to the Participant, the Participant may elect to have the Company withhold a greater number of Shares (up to a maximum of fifty percent (50%) of the Shares distributable to the Participant) for tax withholding.

7. Binding Agreement. Subject to the limitation on the transferability of this award contained herein, this Agreement will be binding upon and inure to the benefit of the heirs, legatees, legal representatives, successors and assigns of the parties hereto.

8. Consent to Electronic Delivery. By executing this Agreement, the Participant hereby consents to the delivery of information (including, without limitation, information required to be delivered to the Participant pursuant to applicable securities laws) regarding the Company and the Subsidiaries, the Plan, and the Retention Stock Units via the Company's website or other electronic delivery.

9. Section and Other Headings, etc. The section and other headings contained in this Agreement are for reference purposes only and shall not affect the meaning or

interpretation of this Agreement.

10. Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which together shall constitute one and the same instrument.

11. Agreement Severable. In the event that any provision in this Agreement will be held invalid or unenforceable, such provision will be severable from, and such invalidity or unenforceability will not be construed to have any effect on, the remaining provisions of this Agreement.

12. Modifications to the Agreement. This Agreement constitutes the entire understanding of the parties on the subjects covered. Modifications to this Agreement can be made only in an express written contract executed by a duly authorized officer of the Company.

13. Governing Law. Except to the extent superseded by the laws of the United States, this Agreement will be governed by, and construed in accordance with, the laws of the State of North Carolina without regard to principles of conflict of laws.

14. Additional Actions. The parties will execute such further instruments and take such further action as may reasonably be necessary to carry out the intent of this Agreement.

IN WITNESS WHEREOF, the Company and the Participant have executed this Agreement as of the Award Date.

PIEDMONT NATURAL GAS COMPANY, INC.

By: /s/ Kevin M. O'Hara

Kevin M. O'Hara
Senior Vice President,
Chief Administrative Officer

/s/ Thomas E. Skains

Thomas E. Skains

Exhibit 31.1

CERTIFICATION

I, Thomas E. Skains, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Piedmont Natural Gas Company, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	March 9, 2012	/s/ Thomas E. Skains
		Thomas E. Skains Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Karl W. Newlin, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Piedmont Natural Gas Company, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2012

/s/ Karl W. Newlin

Karl W. Newlin
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY
ACT OF 2002

In connection with the Quarterly Report of Piedmont Natural Gas Company, Inc. (the "Company"), on Form 10-Q for the period ended January 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Thomas E. Skains, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 9, 2012
/s/ Thomas E. Skains

Thomas E. Skains
Chairman of the Board, President and Chief Executive Officer

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY
ACT OF 2002

In connection with the Quarterly Report of Piedmont Natural Gas Company, Inc. (the "Company"), on Form 10-Q for the period ended January 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Karl W. Newlin, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 9, 2012
/s/ Karl W. Newlin

Karl W. Newlin
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

SOUTHERN CO

FORM 10-Q
(Quarterly Report)

Filed 05/07/12 for the Period Ending 03/31/12

Address	30 IVAN ALLEN JR. BLVD., N.W. ATLANTA, GA 30308
Telephone	4045065000
CIK	0000092122
Symbol	SO
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2012

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _______to ______

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18 th Street Birmingham, Alabama 35203 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
The Southern Company	X			
Alabama Power Company			X	
Georgia Power Company			X	
Gulf Power Company			X	
Mississippi Power Company			X	
Southern Power Company			X	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.) Yes ☐ No ☑ (Response applicable to all registrants.)

Registrant	Description of Common Stock	Shares Outstanding at March 31, 2012
The Southern Company	**Par Value $5 Per Share**	**868,690,126**
Alabama Power Company	**Par Value $40 Per Share**	**30,537,500**
Georgia Power Company	**Without Par Value**	**9,261,500**
Gulf Power Company	**Without Par Value**	**4,542,717**
Mississippi Power Company	**Without Par Value**	**1,121,000**
Southern Power Company	**Par Value $0.01 Per Share**	**1,000**

This combined Form 10-Q is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

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March 31, 2012

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INDEX TO QUARTERLY REPORT ON FORM 10-Q
March 31, 2012

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DEFINITIONS

Term	Meaning
2010 ARP	Alternate Rate Plan approved by the Georgia PSC for Georgia Power, which became effective January 1, 2011 and will continue through December 31, 2013
2011 IRP Update	Georgia Power's 2011 Integrated Resource Plan update filed with the Georgia PSC on August 4, 2011
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
Clean Air Act	Clean Air Act Amendments of 1990
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
ECO Plan	Mississippi Power's Environmental Compliance Overview Plan
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Form 10-K	Combined Annual Report on Form 10-K of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power for the year ended December 31, 2011
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany Interchange Contract
Internal Revenue Code	Internal Revenue Code of 1986, as amended
IRS	Internal Revenue Service
Kemper IGCC	Integrated coal gasification combined cycle facility under construction in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal unit
MW	Megawatt
MWH	Megawatt-hour
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's natural disaster reserve
NRC	Nuclear Regulatory Commission
NSR	New Source Review
OCI	Other Comprehensive Income
PEP	Mississippi Power's Performance Evaluation Plan
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
Power Pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power Purchase Agreement
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power
ROE	Return on equity
SEC	Securities and Exchange Commission

SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, and other subsidiaries
Southern Power	Southern Power Company
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
Westinghouse	Westinghouse Electric Company LLC
wholesale revenues	revenues generated from sales for resale

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, future earnings, access to sources of capital, projections for the qualified pension plan and other postretirement benefit plan contributions, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water, coal combustion byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of Southern Company's employee benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and actions related to the Kemper IGCC, including Mississippi PSC approvals, potential DOE loan guarantees, the SMEPA purchase decision, utilization of investment tax credits, and the outcome of any further proceedings regarding the Mississippi PSC's issuance of the CPCN;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on Southern Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;

- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on Southern Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 3,092**	$ 3,396
Wholesale revenues	**349**	449
Other electric revenues	**148**	150
Other revenues	**15**	17
Total operating revenues	**3,604**	4,012
Operating Expenses:		
Fuel	**1,064**	1,476
Purchased power	**141**	100
Other operations and maintenance	**967**	944
Depreciation and amortization	**441**	418
Taxes other than income taxes	**225**	220
Total operating expenses	**2,838**	3,158
Operating Income	**766**	854
Other Income and (Expense):		
Allowance for equity funds used during construction	**31**	35
Interest expense, net of amounts capitalized	**(211)**	(222)
Other income (expense), net	**(2)**	2
Total other income and (expense)	**(182)**	(185)
Earnings Before Income Taxes	**584**	669
Income taxes	**200**	231
Consolidated Net Income	**384**	438
Dividends on Preferred and Preference Stock of Subsidiaries	**16**	16
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 368**	$ 422
Common Stock Data:		
Earnings per share (EPS) -		
Basic EPS	**$ 0.42**	$ 0.50
Diluted EPS	**$ 0.42**	$ 0.49
Average number of shares of common stock outstanding (in millions)		
Basic	**868**	848
Diluted	**877**	854
Cash dividends paid per share of common stock	**$ 0.4725**	$ 0.4550

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(in millions)	
Consolidated Net Income	**$ 384**	$ 438
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $2 and $2, respectively	**3**	3
Reclassification adjustment for amounts included in net income, net of tax of $1 and $2, respectively	**2**	3
Marketable securities:		
Change in fair value, net of tax of $- and $-, respectively	**—**	(1)
Pension and other post retirement benefit plans:		
Reclassification adjustment for amounts included in net income, net of tax of $1 and $1, respectively	**1**	(1)
Total other comprehensive income (loss)	**6**	4
Dividends on preferred and preference stock of subsidiaries	**(16)**	(16)
Comprehensive Income	**$ 374**	$ 426

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Operating Activities:		
Consolidated net income	**$ 384**	$ 438
Adjustments to reconcile consolidated net income to net cash provided from operating activities —		
Depreciation and amortization, total	**529**	501
Deferred income taxes	**104**	174
Allowance for equity funds used during construction	**(31)**	(35)
Pension, postretirement, and other employee benefits	**16**	(11)
Stock based compensation expense	**25**	21
Other, net	**2**	(16)
Changes in certain current assets and liabilities —		
-Receivables	**372**	276
-Fossil fuel stock	**(218)**	(42)
-Other current assets	**(60)**	(77)
-Accounts payable	**(136)**	(108)
-Accrued taxes	**(167)**	131
-Accrued compensation	**(305)**	(277)
-Other current liabilities	**53**	23
Net cash provided from operating activities	**568**	998
Investing Activities:		
Property additions	**(1,231)**	(1,086)
Distribution of restricted cash	**—**	61
Nuclear decommissioning trust fund purchases	**(336)**	(928)
Nuclear decommissioning trust fund sales	**334**	924
Proceeds from property sales	**2**	14
Cost of removal, net of salvage	**(32)**	(15)
Change in construction payables	**(156)**	136
Other investing activities	**(8)**	10
Net cash used for investing activities	**(1,427)**	(884)
Financing Activities:		
Increase (decrease) in notes payable, net	**174**	(54)
Proceeds —		
Long-term debt issuances	**1,400**	937
Interest-bearing refundable deposit related to asset sale	**150**	—
Common stock issuances	**116**	193
Redemptions —		
Long-term debt	**(827)**	(824)
Payment of common stock dividends	**(410)**	(385)
Payment of dividends on preferred and preference stock of subsidiaries	**(16)**	(16)
Other financing activities	**1**	(2)
Net cash provided from (used for) financing activities	**588**	(151)
Net Change in Cash and Cash Equivalents	**(271)**	(37)
Cash and Cash Equivalents at Beginning of Period	**1,315**	447
Cash and Cash Equivalents at End of Period	**$ 1,044**	$ 410
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (net of $21 and $17 capitalized for 2012 and 2011, respectively)	**$ 178**	$ 197
Income taxes (net of refunds)	**2**	(357)
Noncash transactions — accrued property additions at end of period	**420**	531

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2012	At December 31, 2011
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ **1,044**	$ 1,315
Restricted cash and cash equivalents	**7**	8
Receivables —		
Customer accounts receivable	**936**	1,074
Unbilled revenues	**358**	376
Under recovered regulatory clause revenues	**5**	143
Other accounts and notes receivable	**226**	282
Accumulated provision for uncollectible accounts	**(24)**	(26)
Fossil fuel stock, at average cost	**1,585**	1,367
Materials and supplies, at average cost	**898**	903
Vacation pay	**161**	160
Prepaid expenses	**519**	385
Other regulatory assets, current	**267**	239
Other current assets	**59**	46
Total current assets	**6,041**	6,272
Property, Plant, and Equipment:		
In service	**60,073**	59,744
Less accumulated depreciation	**21,327**	21,154
Plant in service, net of depreciation	**38,746**	38,590
Other utility plant, net	**54**	55
Nuclear fuel, at amortized cost	**830**	774
Construction work in progress	**6,225**	5,591
Total property, plant, and equipment	**45,855**	45,010
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,280**	1,207
Leveraged leases	**654**	649
Miscellaneous property and investments	**260**	262
Total other property and investments	**2,194**	2,118
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,381**	1,365
Unamortized debt issuance expense	**163**	156
Unamortized loss on reacquired debt	**279**	285
Deferred under recovered regulatory clause revenues	**24**	48
Other regulatory assets, deferred	**3,486**	3,532
Other deferred charges and assets	**451**	481
Total deferred charges and other assets	**5,784**	5,867
Total Assets	**$ 59,874**	$ 59,267

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholders' Equity	At March 31, 2012	At December 31, 2011
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,881**	$ 1,717
Interest-bearing refundable deposit related to asset sale	**150**	—
Notes payable	**1,029**	859
Accounts payable	**1,262**	1,553
Customer deposits	**358**	347
Accrued taxes —		
Accrued income taxes	**51**	13
Unrecognized tax benefits	**12**	22
Other accrued taxes	**198**	425
Accrued interest	**249**	226
Accrued vacation pay	**204**	205
Accrued compensation	**158**	450
Liabilities from risk management activities	**219**	209
Other regulatory liabilities, current	**153**	125
Other current liabilities	**393**	426
Total current liabilities	**6,317**	6,577
Long-term Debt	**19,051**	18,647
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**9,001**	8,809
Deferred credits related to income taxes	**220**	224
Accumulated deferred investment tax credits	**651**	611
Employee benefit obligations	**2,432**	2,442
Asset retirement obligations	**1,341**	1,321
Other cost of removal obligations	**1,178**	1,165
Other regulatory liabilities, deferred	**324**	297
Other deferred credits and liabilities	**578**	514
Total deferred credits and other liabilities	**15,725**	15,383
Total Liabilities	**41,093**	40,607
Redeemable Preferred Stock of Subsidiaries	**375**	375
Stockholders' Equity:		
Common Stockholders' Equity:		
Common stock, par value $5 per share —		
Authorized — 1.5 billion shares		
Issued — March 31, 2012: 869 million shares		
— December 31, 2011: 866 million shares		
Treasury — March 31, 2012: 0.5 million shares		
— December 31, 2011: 0.5 million shares		
Par value	**4,346**	4,328
Paid-in capital	**4,550**	4,410
Treasury, at cost	**(18)**	(17)
Retained earnings	**8,926**	8,968
Accumulated other comprehensive loss	**(105)**	(111)
Total Common Stockholders' Equity	**17,699**	17,578
Preferred and Preference Stock of Subsidiaries	**707**	707
Total Stockholders' Equity	**18,406**	18,285
Total Liabilities and Stockholders' Equity	**$ 59,874**	$ 59,267

The accompanying notes as they relate to Southern Company are an integral part of these condensed financial statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRST QUARTER 2012 vs. FIRST QUARTER 2011

OVERVIEW

Southern Company is a holding company that owns all of the common stock of the traditional operating companies — Alabama Power, Georgia Power, Gulf Power, and Mississippi Power — and Southern Power and other direct and indirect subsidiaries. Discussion of the results of operations is focused on the Southern Company system's primary business of electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company's other business activities include investments in leveraged lease projects and telecommunications. For additional information on these businesses, see BUSINESS — The Southern Company System — "Traditional Operating Companies," "Southern Power," and "Other Businesses" in Item 1 of the Form 10-K.

Southern Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and earnings per share. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS — OVERVIEW — "Key Performance Indicators" of Southern Company in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(54)	(12.8)

Southern Company's first quarter 2012 net income after dividends on preferred and preference stock of subsidiaries was $368 million ($0.42 per share) compared to $422 million ($0.50 per share) for the first quarter 2011. The decrease for the first quarter 2012 when compared to the corresponding period in 2011 was primarily the result of a decrease in revenues due to milder weather, an increase in depreciation on additional plant in service related to new generation, transmission, distribution, and environmental projects, an increase in operations and maintenance expenses, and lower energy revenues at Southern Power. The net income decrease for the first quarter 2012 was partially offset by increases in revenues associated with the elimination of a tax-related adjustment under Alabama Power's rate structure, an increase related to retail revenue rate effects at Georgia Power, an increase related to interim retail rate revenues at Gulf Power, and an increase in industrial KWH sales.

Retail Revenues

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(304)	(9.0)

In the first quarter 2012, retail revenues were $3.1 billion compared to $3.4 billion for the corresponding period in 2011.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Details of the change to retail revenues were as follows:

	First Quarter 2012	
	(in millions)	*(% change)*
Retail — prior year	$3,396	
Estimated change in —		
Rates and pricing	59	1.7
Sales growth (decline)	17	0.5
Weather	(113)	(3.3)
Fuel and other cost recovery	(267)	(7.9)
Retail – current year	$3,092	(9.0)%

Revenues associated with changes in rates and pricing increased in the first quarter 2012 when compared to the corresponding period in 2011 primarily due to the elimination of a tax-related adjustment under Alabama Power's rate structure and an increase related to interim retail rate revenues at Gulf Power. Also contributing to the increase were increases in retail revenues at Georgia Power associated with rate pricing effects due to decreased customer usage and the NCCR and demand-side management tariff increases, partially offset by lower contributions from market-driven rates from commercial and industrial customers.

Revenues attributable to changes in sales increased in the first quarter 2012 when compared to the corresponding period in 2011. The increase was due to a 1.9% increase in industrial KWH sales and a 0.6% increase in weather-adjusted residential KWH sales, partially offset by a 1.3% decrease in weather-adjusted commercial KWH sales. Increased demand in the pipelines, transportation, and primary metals sectors was the main contributor to the increase in industrial KWH sales.

Revenues resulting from changes in weather decreased $113 million in the first quarter 2012 as a result of milder weather when compared to the corresponding period in 2011.

Fuel and other cost recovery revenues decreased $267 million in the first quarter 2012 when compared to the corresponding period in 2011. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power costs, and do not affect net income.

Wholesale Revenues

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(100)	(22.3)

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives, unit power sales contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

In the first quarter 2012, wholesale revenues were $349 million compared to $449 million for the corresponding period in 2011, reflecting a $107 million decrease in energy revenues and a $7 million increase in capacity revenues. The decrease in the first quarter 2012 was primarily related to lower energy sales mainly due to lower customer demand and a reduction in the average price of energy.

Fuel and Purchased Power Expenses

First Quarter 2012 vs. First Quarter 2011		
	(change in millions)	*(% change)*
Fuel	$ (412)	(27.9)
Purchased power	41	41.0
Total fuel and purchased power expenses	$ (371)	

In the first quarter 2012, total fuel and purchased power expenses were $1.2 billion compared to $1.6 billion for the corresponding period in 2011. The decrease in the first quarter 2012 when compared to the corresponding period in 2011 was primarily the result of a $395 million decrease in the average cost of fuel and purchased power, partially offset by a $24 million net increase related to total KWHs generated and purchased.

Fuel expenses at the traditional operating companies are generally offset by fuel revenues and do not have a significant effect on net income. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Retail Fuel Cost Recovery" herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly affect net income.

Details of the Southern Company system's generation and purchased power were as follows:

	First Quarter 2012	First Quarter 2011
Total generation *(billions of KWHs)*	**39**	46
Total purchased power *(billions of KWHs)*	**4**	1
Sources of generation *(percent)* —		
Coal	**35**	53
Nuclear	**19**	16
Gas	**42**	28
Hydro	**4**	3
Cost of fuel, generated *(cents per net KWH)* —		
Coal	**4.09**	3.96
Nuclear	**0.80**	0.67
Gas	**2.77**	3.93
Average cost of fuel, generated *(cents per net KWH)*	**2.85**	3.39
Average cost of purchased power *(cents per net KWH)**	**3.88**	9.25

* Average cost of purchased power includes fuel purchased by the electric utilities for tolling agreements where power is generated by the provider.

In the first quarter 2012, fuel expense was $1.1 billion compared to $1.5 billion for the corresponding period in 2011. The decrease in the first quarter 2012 when compared to the corresponding period in 2011 was primarily due to a 29.5% decrease in the average cost of gas per KWH generated, a higher percentage of generation from lower cost natural gas-fired resources, and lower customer demand mainly due to milder weather.

In the first quarter 2012, purchased power expense was $141 million compared to $100 million for the corresponding period in 2011. The increase in the first quarter 2012 when compared to the corresponding period in 2011 was primarily due to a 298.2% increase in the volume of KWHs purchased as the market cost of available energy was lower than the marginal cost of generation available, partially offset by a 58.1% decrease in the average cost per KWH purchased.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Energy purchases will vary depending on demand for energy within the Southern Company system's service territory, the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, and the availability of the Southern Company system's generation.

Other Operations and Maintenance Expenses

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$23	2.4

In the first quarter 2012, other operations and maintenance expenses were $967 million compared to $944 million for the corresponding period in 2011. The increase in the first quarter 2012 when compared to the corresponding period in 2011 was primarily the result of a $43 million increase in administrative and general costs primarily due to increases in pension costs, property insurance, and other employee benefits. Also contributing to the increase was a $6 million increase in customer service and sales related costs. The increase in the first quarter 2012 was partially offset by a $13 million decrease primarily related to scheduled outage and maintenance costs and commodity and labor costs, as well as an $11 million decrease at Mississippi Power related to the expiration of an operating lease for Plant Daniel Units 3 and 4. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Purchase of the Plant Daniel Combined Cycle Generating Units" of Southern Company in Item 7 of the Form 10-K for additional information.

Depreciation and Amortization

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$23	5.5

In the first quarter 2012, depreciation and amortization was $441 million compared to $418 million for the corresponding period in 2011. The increase for the first quarter 2012 when compared to the corresponding period in 2011 was primarily the result of an increase in depreciation due to additional plant in service related to new generation at Georgia Power's Plant McDonough Unit 4 that went into service in December 2011, as well as transmission, distribution, and environmental projects.

Allowance for Equity Funds Used During Construction

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(4)	(11.4)

In the first quarter 2012, AFUDC equity was $31 million compared to $35 million for the corresponding period in 2011. The decrease for the first quarter 2012 when compared to the corresponding period in 2011 was primarily due to the completion of Georgia Power's Plant McDonough Unit 4 in December 2011, partially offset by CWIP related to Mississippi Power's Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(11)	(5.0)

In the first quarter 2012, interest expense, net of amounts capitalized was $211 million compared to $222 million for the corresponding period in 2011. The decrease for the first quarter 2012 when compared to the corresponding period in 2011 was primarily due to lower interest rates on outstanding debt and a refinancing of long-term debt during 2011 at

Southern Power. Also contributing to the decrease was an increase in capitalized interest associated with construction projects at Southern Power.

Income Taxes

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(31)	(13.4)

In the first quarter 2012, income taxes were $200 million compared to $231 million for the corresponding period in 2011. The decrease for the first quarter 2012 when compared to the corresponding period in 2011 was primarily the result of lower pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Company's future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Company's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Another major factor is the profitability of the competitive wholesale supply business. Future earnings for the electricity business in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities and other wholesale customers, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, and the successful remarketing of capacity as current contracts expire. Changes in economic conditions impact sales for the traditional operating companies and Southern Power, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL of Southern Company in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — New Source Review Actions" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters — New Source Review Actions" in Item 8 of the Form 10-K for additional information. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power (including claims related to a unit co-owned by Mississippi Power). At the same time, the EPA asked the U.S. Court of Appeals for the Eleventh Circuit to stay its appeal of the judgment in favor of Alabama Power. Alabama Power filed oppositions to the EPA's motion and its request for a stay. On March 29, 2012, the U.S. Court of Appeals for the Eleventh Circuit denied the EPA's request to stay its appeal. The U.S. District Court for the Northern District of Alabama has not ruled on the EPA's motion seeking vacatur of the judgment. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Hurricane Katrina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Climate Change Litigation — Hurricane Katrina Case" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Environmental Matters — Climate Change Litigation — Hurricane Katrina Case" in Item 8 of the Form 10-K for additional information. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the amended class action complaint filed on May 27, 2011 by the plaintiffs. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Environmental Statutes and Regulations — General" of Southern Company in Item 7 of the Form 10-K for information regarding the Southern Company system's estimated base level capital expenditures to comply with existing statutes and regulations for 2012 through 2014, as well as the Southern Company system's preliminary estimates for potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) and the EPA's proposed water and coal combustion byproducts rules. The Southern Company system is continuing to develop its compliance strategy and to assess the potential costs of complying with the MATS rule and the EPA's proposed water and coal combustion byproducts rules.

The Southern Company system's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including any proposed environmental regulations; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Southern Company system's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

As part of Southern Electric Generating Company's (SEGCO) environmental compliance strategy, the Board of Directors of SEGCO approved adding natural gas as the primary fuel source in 2015 for its 1,000 MWs of generating capacity and the construction of the necessary natural gas pipeline. SEGCO is jointly owned by Alabama Power and Georgia Power. The capacity of SEGCO's units is sold to Alabama Power and Georgia Power through a PPA. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material impact on Southern Company's financial statements.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Environmental Statutes and Regulations — Air Quality" of Southern Company in Item 7 of the Form 10-K for additional information on the eight-hour ozone air quality standards and the MATS rule.

On May 1, 2012, the EPA released its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. The only area within the traditional operating companies' service territory designated as a nonattainment area was a 15-county area within metropolitan Atlanta.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by Southern Company and its subsidiaries, have been filed with the EPA. Challenges to the final rule have also been filed in the U.S. District Court of Appeals for the District of Columbia by numerous states, environmental organizations, industry groups, and others. The impact of the MATS rule will depend on the outcome of these and any other legal challenges and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Environmental Statutes and Regulations — Coal Combustion Byproducts" of Southern Company in Item 7 of the Form 10-K for additional information. On April 5, 2012, 10 environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts as soon as possible. Other parties are expected to file similar challenges. The ultimate outcome of this matter cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Global Climate Issues" of Southern Company in Item 7 of the Form 10-K for additional information. On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. As proposed, the standards would not apply to existing units. The EPA has delayed its plans to propose greenhouse gas emissions performance standards for modified sources and emissions guidelines for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

PSC Matters

Retail Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. The traditional operating companies have experienced lower pricing for natural gas resulting in an increase in natural gas generation and a decrease in coal generation, which is currently more costly. The lower cost of natural gas has resulted in total over recovered fuel costs at Georgia Power, Gulf Power, and Mississippi Power included in Southern Company's Condensed Balance Sheets herein of approximately $102 million at March 31, 2012. At March 31, 2012, Alabama Power had under recovered fuel costs included in Southern Company's Condensed Balance Sheet herein of approximately $6 million. At December 31, 2011, total under recovered fuel costs at Alabama Power and Georgia Power included in Southern Company's Condensed Balance Sheet herein were approximately $169 million, and Gulf Power and Mississippi Power had a total over recovered fuel balance included in Southern Company's Condensed Balance Sheet herein of approximately $52 million. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect annual cash flow. The traditional operating companies continuously monitor their under or over recovered fuel cost balances.

On March 30, 2012, Georgia Power filed a request with the Georgia PSC to decrease fuel rates by 19%, which is expected to reduce annual billings by $567 million. The decrease in fuel costs is driven primarily by lower natural gas prices as a result of increased natural gas supplies. The Georgia PSC is scheduled to vote on this matter on June 21, 2012. As proposed, the rate decrease would become effective July 1, 2012; however, Georgia Power is currently working with the Georgia PSC to potentially implement the proposed decrease effective June 1, 2012. The ultimate outcome of this matter cannot be determined at this time.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "PSC Matters — Fuel Cost Recovery" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters — Alabama Power — Fuel Cost Recovery" and "Retail Regulatory Matters — Georgia Power — Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information.

Georgia Power

2011 Integrated Resource Plan Update

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Environmental Statutes and Regulations — Air Quality," "— Water Quality," and "— Coal Combustion Byproducts" of Southern Company in Item 7 and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters — Georgia Power — Rate Plans" and "— 2011 Integrated Resource Plan Update" in Item 8 of the Form 10-K for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; the 2010 ARP; and the 2011 IRP Update.

On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire two coal-fired generation units at Plant Branch as of October 31, 2013 and December 31, 2013 and an oil-fired unit at Plant Mitchell as of March 26, 2012, which was included in Georgia Power's 2011 IRP Update. The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. The PPAs remain subject to FERC approval. The ultimate outcome of this matter cannot be determined at this time.

Income Tax Matters

Bonus Depreciation

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Southern Company through 2013. Due to the significant amount of estimated bonus depreciation for 2012, a portion of Southern Company's tax credit utilization will be deferred. Consequently, Southern Company's positive cash flow benefit is estimated to be between $530 million and $720 million in 2012.

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, including natural gas, biomass, and solar units at Southern Power, natural gas units and Plant Vogtle Units 3 and 4 at Georgia Power, and the Kemper IGCC at Mississippi Power, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approvals in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. See Note 7 to the financial statements of Southern Company under "Construction

Program" in Item 8 of the Form 10-K for estimated construction expenditures for the next three years. In addition, see Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters — Georgia Power — Nuclear Construction," "Retail Regulatory Matters — Georgia Power — Other Construction," and "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and Note (B) to the Condensed Financial Statements under "Retail Regulatory Matters — Georgia Power — Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" herein for additional information.

Investments in Leveraged Leases

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Investments in Leveraged Leases" of Southern Company in Item 7 and Note 1 to the financial statements of Southern Company under "Leveraged Leases" in Item 8 of the Form 10-K for additional information.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the assets. Southern Company is currently engaged in discussions with the lessee and the holders of the project's nonrecourse debt to restructure the debt payments and the related rental payments to allow additional capital investment in the project to be made to improve the operation of the generation assets and the financial viability of the lease transaction. Southern Company continues to monitor the performance of the underlying assets and to evaluate the ability of the lessee to continue to make the required lease payments. If the attempts at restructuring the project are unsuccessful and the project is ultimately abandoned, the potential impairment loss that would be incurred is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Southern Company in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Other Matters" of Southern Company in Item 7 of the Form 10-K for additional information regarding the earthquake and tsunami that struck Japan in March 2011. On March 12, 2012, the NRC issued three orders and a request for information based on the NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. The staff of the NRC expects to issue additional implementation guidance by August 2012. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the

NRC and cannot be determined at this time. See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Company in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS — ACCOUNTING POLICIES — "Application of Critical Accounting Policies and Estimates" of Southern Company in Item 7 of the Form 10-K for a complete discussion of Southern Company's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Overview" of Southern Company in Item 7 of the Form 10-K for additional information. Southern Company's financial condition remained stable at March 31, 2012. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $568 million for the first quarter 2012, a decrease of $430 million from the corresponding period in 2011. Significant changes in operating cash flow for the first quarter 2012 compared to the corresponding period in 2011 include an increase in fossil fuel stock levels due to reduced consumption as a result of milder weather in the first quarter 2012 and a decrease in accrued taxes primarily due to the timing of tax payments. Net cash used for investing activities totaled $1.4 billion for the first quarter 2012, an increase of $543 million from the corresponding period in 2011. This increase was primarily due to property additions to utility plant. Net cash provided from financing activities totaled $588 million for the first quarter 2012 compared to $151 million net cash used for financing activities in the corresponding period in 2011. This change was primarily due to an increase in short-term debt outstanding, an increase in long-term debt issuances, and the receipt of an interest-bearing refundable deposit related to a pending asset sale at Mississippi Power.

Significant balance sheet changes for the first quarter 2012 include an increase of $845 million in total property, plant, and equipment for the construction of generation, transmission, and distribution facilities. Other significant changes include an increase in long-term debt of $404 million due to senior note issuances.

The market price of Southern Company's common stock at the end of the first quarter 2012 was $44.93 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $20.37 per share, representing a market-to-book ratio of 221%, compared to $46.29, $20.32, and 228%, respectively, at the end of 2011. The dividend for the first quarter 2012 was $0.4725 per share compared to $0.4550 per share in the first quarter 2011. In April 2012, the quarterly dividend payable in June 2012 was increased to $0.49 per share.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Capital Requirements and Contractual Obligations" of Southern Company in Item 7 of the Form 10-K for a description of Southern Company's capital requirements for the construction programs of the Southern Company system and other funding requirements associated with scheduled maturities of long-term debt, as well as the related interest, preferred and preference stock dividends, leases, trust funding requirements, other purchase commitments, unrecognized tax benefits and interest, and derivative obligations. Approximately $1.9 billion will be required through March 31, 2013 to fund maturities and announced redemptions of long-term debt.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of Southern Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2012, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

Except as described below with respect to potential DOE loan guarantees, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Sources of Capital" of Southern Company in Item 7 of the Form 10-K for additional information.

In June 2010, Georgia Power reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future Georgia Power borrowings related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for Georgia Power.

In addition, Mississippi Power has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. Mississippi Power is in advanced due diligence with the DOE. There can be no assurance that the DOE will issue federal loan guarantees for Mississippi Power. Mississippi Power also received DOE grant funds of $245 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for the initial operation of the Kemper IGCC.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business of the Southern Company system. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs which are backed by bank credit facilities.

At March 31, 2012, Southern Company and its subsidiaries had approximately $1.0 billion of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2012 were as follows:

	Expires					Executable Term Loans		Due Within One Year (a)	
Company	**2012**	**2013**	**2014 and Beyond**	**Total**	**Unused**	**One Year**	**Two Year**	**Term Out**	**No Term Out**
	(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ —	$ —	$1,000	$1,000	$1,000	$ —	$—	$ —	$ —
Alabama Power	121	35	1,150	1,306	1,306	51	—	51	71
Georgia Power	—	—	1,750	1,750	1,745	—	—	—	—
Gulf Power	75	35	165	275	275	75	—	75	35
Mississippi Power	106	25	165	296	296	25	41	66	65
Southern Power	—	—	500	500	500	—	—	—	—
Other	25	25	—	50	50	25	—	25	—
Total	$327	$120	$4,730	$5,177	$5,172	$176	$41	$217	$171

(a) Reflects facilities expiring on or before March 31, 2013.

See Note 6 to the financial statements of Southern Company under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2012 was approximately $1.8 billion.

The traditional operating companies may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of each of the traditional operating companies.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Details of short-term borrowings, excluding $2 million in notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	**Weighted Average Interest Rate**	**Average Outstanding**	**Weighted Average Interest Rate**	**Maximum Amount Outstanding**
	(in millions)		*(in millions)*		*(in millions)*
March 31, 2012:					
Commercial paper	$ 728	0.3%	$583	0.3%	$938
Short-term bank debt	300	1.1%	290	1.2%	300
Total	$1,028	0.6%	$873	0.6%	

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Southern Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at March 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	624
Below BBB- and/or Baa3	2,833

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Southern Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Southern Company is exposed to market risks, primarily commodity price risk and interest rate risk. Southern Company may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, Southern Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Southern Company's policies in areas such as counterparty exposure and risk management practices. Southern Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter into physical fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the first quarter 2012 when compared with the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2012 were as follows:

	First Quarter 2012 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(231)
Contracts realized or settled	50
Current period changes [(a)]	(84)
Contracts outstanding at the end of the period, assets (liabilities), net	$(265)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the three months ended March 31, 2012 was a decrease of $34 million, of which $18 million related to natural gas swaps, $15 million related to natural gas options, and $1 million related to other energy-related derivatives. The change is attributable to both the volume of mmBtu and the price of natural gas. At March 31, 2012, Southern Company had a net hedge volume of 221 million mmBtu, which consisted of 123 million mmBtu of swaps and 98 million mmBtu of options. The weighted average swap contract cost was approximately $1.71 per mmBtu above market prices. At December 31, 2011, Southern Company had a net hedge volume of 189 million mmBtu, which consisted of 123 million mmBtu of swaps and 66 million mmBtu of options. The weighted average swap contract cost was approximately $1.51 per mmBtu above market prices. The change in option premiums is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

The net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	**March 31, 2012**	**December 31, 2011**
	(in millions)	
Regulatory hedges	**$(249)**	$(221)
Cash flow hedges	**(1)**	(1)
Not designated	**(15)**	(9)
Total fair value	**$(265)**	$(231)

Energy-related derivative contracts which are designated as regulatory hedges relate to the traditional operating companies' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives that are designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in income for the three months ended March 31, 2012 and 2011 were not material.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2012 were as follows:

	March 31, 2012 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$—
Level 2	(265)	(197)	(66)	(2)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(265)	$(197)	$(66)	$ (2)

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by Southern Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until all relevant regulations are finalized.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Market Price Risk" of Southern Company in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Southern Company in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

During the first quarter 2012, Southern Company issued approximately 3.6 million shares of common stock for $115 million through employee and director stock plans. The proceeds were primarily used for general corporate purposes, including the investment by Southern Company in its subsidiaries, and to repay short-term indebtedness. While Southern Company continues to issue additional equity through its employee and director equity compensation plans, Southern Company is not currently issuing additional shares of common stock through the Southern Investment Plan or its employee savings plan. All sales under the Southern Investment Plan and the employee savings plan are currently being funded with shares acquired on the open market by the independent plan administrators.

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The following table outlines the debt financing activities for the quarter ended March 31, 2012:

Company*	**Senior Note Issuances**	**Senior Note Redemptions and Maturities**	**Other Long-Term Debt Redemptions and Maturities**
		(in millions)	
Southern Company	$ —	$500	$ —
Alabama Power	250	—	1
Georgia Power	750	—	250
Mississippi Power	400	—	75
Total	$1,400	$500	$326

* Gulf Power and Southern Power did not issue or redeem any long-term debt during the first quarter 2012.

Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for the redemptions and maturities shown in the table above to repay short-term indebtedness and for general corporate purposes, including their respective continuous construction programs.

On January 17, 2012, Southern Company's $500 million aggregate principal amount of Series 2007A 5.30% Senior Notes matured.

On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of a 17.5% undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power's senior unsecured credit rating falls below a BBB+ and/or Baa1.

Subsequent to March 31, 2012, Alabama Power redeemed $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047.

Subsequent to March 31, 2012, Mississippi Power announced the redemption of $90 million aggregate principal amount of its Series E 5-5/8% Senior Notes due May 1, 2033 that will occur on May 15, 2012.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

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PART I

Item 3. Quantitative And Qualitative Disclosures About Market Risk.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Market Price Risk" herein for each registrant and Note 1 to the financial statements of each registrant under "Financial Instruments," Note 11 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Note 10 to the financial statements of Gulf Power and Mississippi Power, and Note 9 to the financial statements of Southern Power in Item 8 of the Form 10-K. Also, see Note (H) to the Condensed Financial Statements herein for information relating to derivative instruments.

Item 4. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures.

As of the end of the period covered by this quarterly report, Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

(b) Changes in internal controls.

There have been no changes in Southern Company's and Alabama Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the first quarter 2012 that have materially affected or are reasonably likely to materially affect Southern Company's or Alabama Power's internal control over financial reporting, other than as described in the next sentence. During the first quarter 2012, Alabama Power implemented new accounts payable, supply chain, and work management systems. The implementation of these systems provides additional operational and internal control benefits including system security and automation of previously manual controls. These process improvement initiatives were not in response to an identified internal control deficiency.

There have been no changes in Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the first quarter 2012 that have materially affected or are reasonably likely to materially affect Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting.

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 1,092**	$ 1,126
Wholesale revenues, non-affiliates	**61**	68
Wholesale revenues, affiliates	**14**	75
Other revenues	**49**	51
Total operating revenues	**1,216**	1,320
Operating Expenses:		
Fuel	**306**	395
Purchased power, non-affiliates	**15**	11
Purchased power, affiliates	**40**	46
Other operations and maintenance	**321**	297
Depreciation and amortization	**157**	157
Taxes other than income taxes	**86**	85
Total operating expenses	**925**	991
Operating Income	**291**	329
Other Income and (Expense):		
Allowance for equity funds used during construction	**5**	5
Interest income	**4**	4
Interest expense, net of amounts capitalized	**(73)**	(74)
Other income (expense), net	**(7)**	(6)
Total other income and (expense)	**(71)**	(71)
Earnings Before Income Taxes	**220**	258
Income taxes	**84**	96
Net Income	**136**	162
Dividends on Preferred and Preference Stock	**10**	10
Net Income After Dividends on Preferred and Preference Stock	**$ 126**	$ 152

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Net Income After Dividends on Preferred and Preference Stock	**$ 126**	$ 152
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $3 and $2, respectively	**4**	2
Total other comprehensive income (loss)	**4**	2
Comprehensive Income	**$ 130**	$ 154

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

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ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in millions)	
Operating Activities:		
Net income	**$ 136**	$ 162
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**189**	185
Deferred income taxes	**31**	59
Allowance for equity funds used during construction	**(5)**	(5)
Pension, postretirement, and other employee benefits	**(1)**	(11)
Stock based compensation expense	**4**	3
Other, net	**(10)**	1
Changes in certain current assets and liabilities —		
-Receivables	**89**	51
-Fossil fuel stock	**(81)**	3
-Materials and supplies	**2**	10
-Other current assets	**(51)**	(69)
-Accounts payable	**(149)**	(153)
-Accrued taxes	**43**	160
-Accrued compensation	**(63)**	(67)
-Other current liabilities	**6**	(2)
Net cash provided from operating activities	**140**	327
Investing Activities:		
Property additions	**(244)**	(213)
Distribution of restricted cash from pollution control revenue bonds	**—**	11
Nuclear decommissioning trust fund purchases	**(49)**	(97)
Nuclear decommissioning trust fund sales	**49**	97
Cost of removal, net of salvage	**(6)**	(8)
Change in construction payables	**14**	(2)
Other investing activities	**1**	(12)
Net cash used for investing activities	**(235)**	(224)
Financing Activities:		
Proceeds —		
Capital contributions from parent company	**5**	5
Senior notes issuances	**250**	250
Redemptions —		
Pollution control revenue bonds	**(1)**	—
Senior notes	**—**	(200)
Payment of preferred and preference stock dividends	**(10)**	(10)
Payment of common stock dividends	**(135)**	(138)
Other financing activities	**(3)**	(5)
Net cash provided from (used for) financing activities	**106**	(98)
Net Change in Cash and Cash Equivalents	**11**	5
Cash and Cash Equivalents at Beginning of Period	**344**	154
Cash and Cash Equivalents at End of Period	**$ 355**	$ 159
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (net of $2 and $2 capitalized for 2012 and 2011, respectively)	**$ 66**	$ 72
Income taxes (net of refunds)	**22**	(110)
Noncash transactions — accrued property additions at end of period	**32**	26

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

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ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2012	At December 31, 2011
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ **355**	$ 344
Restricted cash and cash equivalents	**—**	1
Receivables —		
Customer accounts receivable	**300**	332
Unbilled revenues	**116**	126
Other accounts and notes receivable	**35**	35
Affiliated companies	**50**	79
Accumulated provision for uncollectible accounts	**(10)**	(10)
Fossil fuel stock, at average cost	**425**	344
Materials and supplies, at average cost	**372**	375
Vacation pay	**59**	59
Prepaid expenses	**146**	74
Other regulatory assets, current	**48**	44
Other current assets	**12**	11
Total current assets	**1,908**	1,814
Property, Plant, and Equipment:		
In service	**20,999**	20,809
Less accumulated provision for depreciation	**7,446**	7,344
Plant in service, net of depreciation	**13,553**	13,465
Nuclear fuel, at amortized cost	**363**	330
Construction work in progress	**339**	374
Total property, plant, and equipment	**14,255**	14,169
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**62**	62
Nuclear decommissioning trusts, at fair value	**588**	540
Miscellaneous property and investments	**74**	73
Total other property and investments	**724**	675
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**530**	532
Prepaid pension costs	**67**	59
Deferred under recovered regulatory clause revenues	**24**	48
Other regulatory assets, deferred	**995**	994
Other deferred charges and assets	**161**	186
Total deferred charges and other assets	**1,777**	1,819
Total Assets	**$ 18,664**	$ 18,477

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder’s Equity	At March 31, 2012	At December 31, 2011
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 750**	$ 500
Accounts payable —		
Affiliated	**163**	203
Other	**225**	322
Customer deposits	**86**	85
Accrued taxes —		
Accrued income taxes	**44**	32
Other accrued taxes	**54**	34
Accrued interest	**67**	63
Accrued vacation pay	**48**	48
Accrued compensation	**33**	95
Liabilities from risk management activities	**51**	54
Other regulatory liabilities, current	**19**	18
Other current liabilities	**40**	38
Total current liabilities	**1,580**	1,492
Long-term Debt	**5,630**	5,632
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,287**	3,257
Deferred credits related to income taxes	**82**	83
Accumulated deferred investment tax credits	**147**	149
Employee benefit obligations	**343**	343
Asset retirement obligations	**561**	553
Other cost of removal obligations	**719**	703
Other regulatory liabilities, deferred	**193**	156
Other deferred credits and liabilities	**87**	82
Total deferred credits and other liabilities	**5,419**	5,326
Total Liabilities	**12,629**	12,450
Redeemable Preferred Stock	**342**	342
Preference Stock	**343**	343
Common Stockholder’s Equity:		
Common stock, par value $40 per share —		
Authorized - 40,000,000 shares		
Outstanding - 30,537,500 shares	**1,222**	1,222
Paid-in capital	**2,194**	2,182
Retained earnings	**1,948**	1,956
Accumulated other comprehensive loss	**(14)**	(18)
Total common stockholder’s equity	**5,350**	5,342
Total Liabilities and Stockholder’s Equity	**$ 18,664**	$ 18,477

The accompanying notes as they relate to Alabama Power are an integral part of these condensed financial statements.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRST QUARTER 2012 vs. FIRST QUARTER 2011

OVERVIEW

Alabama Power operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service territory located within the State of Alabama in addition to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Alabama Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel, capital expenditures, and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Alabama Power for the foreseeable future.

Alabama Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS — OVERVIEW — "Key Performance Indicators" of Alabama Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(26)	(17.1)

Alabama Power's net income after dividends on preferred and preference stock for the first quarter 2012 was $126 million compared to $152 million for the corresponding period in 2011. The decrease in net income was related to a decrease in weather-related revenues due to milder weather in the first quarter 2012 and an increase in operations and maintenance expenses. The reductions in net income were partially offset by increases in revenues associated with the elimination of a tax-related adjustment under Alabama Power's rate structure and an increase in energy sales due to an increase in customer demand. See BUSINESS – "Rate Matters – Rate Structure and Cost Recovery Plans" of Alabama Power in Item 1 and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" of Alabama Power in Item 7 of the Form 10-K for information regarding the rate structure of Alabama Power.

Retail Revenues

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(34)	(3.0)

In the first quarter 2012, retail revenues were $1.09 billion compared to $1.13 billion for the corresponding period in 2011.

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Details of the change to retail revenues were as follows:

	First Quarter 2012	
	(in millions)	*(% change)*
Retail – prior year	$1,126	
Estimated change in –		
Rates and pricing	25	2.2
Sales growth (decline)	19	1.8
Weather	(50)	(4.5)
Fuel and other cost recovery	(28)	(2.5)
Retail – current year	$1,092	(3.0)%

Revenues associated with changes in rates and pricing increased in the first quarter 2012 when compared to the corresponding period in 2011 primarily due to the elimination of a tax-related adjustment under Alabama Power's rate structure that was effective with October 2011 billings, slightly offset by decreased revenues associated with Rate Certificated New Plant Environmental.

Revenues attributable to changes in sales increased in the first quarter 2012 when compared to the corresponding period in 2011. Industrial KWH energy sales increased 3.2% due to an increase in demand resulting from changes in production levels primarily in the primary metals, chemicals, and forest products sectors, partially offset by a decrease in the stone, clay, and glass sector. Weather-adjusted residential KWH energy sales increased 1.5% due to an increase in customer demand. The decrease in weather-adjusted commercial KWH energy sales was not material.

Revenues resulting from changes in weather decreased in the first quarter 2012 when compared to the corresponding period in 2011. Alabama Power's service territory experienced milder weather conditions in first quarter 2012 resulting in decreases of 9.0% and 1.6% for residential and commercial sales revenue, respectively.

Fuel and other cost recovery revenues decreased in the first quarter 2012 when compared to the corresponding period in 2011 primarily due to lower fuel costs associated with decreased KWH generation and lower average cost per KWH generated due to lower natural gas prices. Electric rates include provisions to recognize the full recovery of fuel costs, purchased power costs, PPAs certificated by the Alabama PSC, and costs associated with the NDR. Under these provisions, fuel and other cost recovery revenues generally equal fuel and other cost recovery expenses and do not affect net income.

See BUSINESS – "Rate Matters – Rate Structure and Cost Recovery Plans" of Alabama Power in Item 1, MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Wholesale Revenues – Non-Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(7)	(10.3)

Wholesale revenues from sales to non-affiliates will vary depending on the market prices of available wholesale energy compared to the cost of Alabama Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

In the first quarter 2012, wholesale revenues from non-affiliates were $61 million compared to $68 million for the corresponding period in 2011, reflecting an $8 million decrease in revenue from energy sales and a $1 million increase in capacity revenue. The decrease was primarily due to an 8.1% decrease in KWH sales and a 1.3% decrease in the price of energy.

Wholesale Revenues – Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(61)	(81.3)

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through Alabama Power's energy cost recovery clauses.

In the first quarter 2012, wholesale revenues from affiliates were $14 million compared to $75 million for the corresponding period in 2011. The decrease was due to a 24.3% decrease in the price of energy and a 75.1% decrease in KWH sales.

Fuel and Purchased Power Expenses

	First Quarter 2012 vs. First Quarter 2011	
	(change in millions)	*(% change)*
Fuel	$(89)	(22.5)
Purchased power – non-affiliates	4	36.4
Purchased power – affiliates	(6)	(13.0)
Total fuel and purchased power expenses	$(91)	

In the first quarter 2012, total fuel and purchased power expenses were $361 million compared to $452 million for the corresponding period in 2011. The decrease was primarily due to an $84 million decrease related to a reduction in total KWHs generated as a result of milder weather in the first quarter 2012, a $4 million decrease in the cost of fuel, and an $8 million decrease in the average cost of purchased power.

Fuel and purchased power energy transactions do not have a significant impact on earnings since energy expenses are generally offset by energy revenues through Alabama Power's Energy Cost Recovery Rate mechanism. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein for additional information.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Details of Alabama Power's generation and purchased power were as follows:

	First Quarter 2012	First Quarter 2011
Total generation *(billions of KWHs)*	**14**	16
Total purchased power *(billions of KWHs)*	**1**	1
Sources of generation *(percent)* –		
Coal	**42**	55
Nuclear	**27**	23
Gas	**20**	15
Hydro	**11**	7
Cost of fuel, generated *(cents per net KWH)* –		
Coal	**3.43**	2.99
Nuclear	**0.74**	0.67
Gas	**3.00**	4.16
Average cost of fuel, generated *(cents per net KWH)**	**2.51**	2.62
Average cost of purchased power *(cents per net KWH)***	**4.60**	5.26

* KWHs generated by hydro are excluded from the average cost of fuel, generated.

** Average cost of purchased power includes fuel purchased by Alabama Power for tolling agreements where power is generated by the provider.

Fuel

In the first quarter 2012, fuel expense was $306 million compared to $395 million for the corresponding period in 2011. The $89 million decrease was due to a 35.7% decrease in KWHs generated by coal and a 27.9% decrease in the average cost of KWHs generated by natural gas, which excludes fuel associated with tolling agreements, slightly offset by a 10% increase in KWHs generated by natural gas.

Purchased Power – Non-Affiliates

In the first quarter 2012, purchased power expense from non-affiliates was $15 million compared to $11 million for the corresponding period in 2011. The increase was related to a 296.5% increase in the amount of energy purchased, partially offset by a 68.0% decrease in the average cost per KWH.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the first quarter 2012, purchased power expense from affiliates was $40 million compared to $46 million for the corresponding period in 2011. The decrease was related to a 13.9% decrease in the amount of energy purchased, slightly offset by a 2.1% increase in the average cost per KWH.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Other Operations and Maintenance Expenses

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$24	8.1

In the first quarter 2012, other operations and maintenance expenses were $321 million compared to $297 million for the corresponding period in 2011. Administrative and general expenses increased $18 million due to benefit-related expenses, affiliated service company expenses, labor expenses, and property insurance expenses. Nuclear production expenses increased $6 million primarily due to the amortization of nuclear outage expenses. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" of Alabama Power in Item 7 of the Form 10-K for additional information.

Income Taxes

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(12)	(12.5)

For the first quarter 2012, income taxes were $84 million compared to $96 million for the corresponding period in 2011. The decrease was primarily due to lower pre-tax earnings as a result of lower revenues due to milder weather.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Alabama Power's future earnings potential. The level of Alabama Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Alabama Power's primary business of selling electricity. These factors include Alabama Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Alabama Power's service territory. Changes in economic conditions impact sales for Alabama Power and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Alabama Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – New Source Review Actions" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K for additional information. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power. At the same time, the EPA asked the U.S. Court of Appeals for the Eleventh Circuit to stay its appeal of the judgment in favor of Alabama Power. Alabama Power filed oppositions to the EPA's motion and its request for a stay. On March 29, 2012, the U.S. Court of Appeals for the Eleventh Circuit denied the EPA's request to stay its appeal. The U.S. District Court for the Northern District of Alabama has not ruled on the EPA's motion seeking vacatur of the judgment. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Hurricane Katrina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Climate Change Litigation – Hurricane Katrina Case" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Environmental Matters – Climate Change Litigation – Hurricane Katrina Case" in Item 8 of the Form 10-K for additional information. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the amended class action complaint filed on May 27, 2011 by the plaintiffs. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – General" of Alabama Power in Item 7 of the Form 10-K for information regarding Alabama Power's estimated base level capital expenditures to comply with existing statutes and regulations for 2012 through 2014, as well as Alabama Power's preliminary estimates for potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) and the EPA's proposed water and coal combustion byproducts rules.

Alabama Power is continuing to develop its compliance strategy and to assess the potential costs of complying with the MATS rule and the EPA's proposed water and coal combustion byproducts rules. As part of its compliance strategy, Alabama Power has entered into agreements for the construction of two baghouses to control the emissions of mercury and particulates from generating units with an aggregate capacity of 1,901 MWs. The cost of the two baghouses is included in the estimated costs associated with compliance with the MATS rule detailed in the Form 10-K, as referenced above.

Alabama Power's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including any proposed environmental regulations; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and Alabama Power's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. Alabama Power's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

As part of Southern Electric Generating Company's (SEGCO) environmental compliance strategy, the Board of Directors of SEGCO approved adding natural gas as the primary fuel source in 2015 for its 1,000 MWs of generating capacity and the construction of the necessary natural gas pipeline. SEGCO is jointly owned by Alabama Power and Georgia Power. The capacity of SEGCO's units is sold to Alabama Power and Georgia Power through a PPA. See Note 4 to the financial statements of Alabama Power in Item 8 of the Form 10-K for additional information. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material impact on Alabama Power's financial statements.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Alabama Power in Item 7 of the Form 10-K for additional information on the eight-hour ozone air quality standards and the MATS rule.

On May 1, 2012, the EPA released its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. None of the areas within Alabama Power's service territory were designated as nonattainment areas.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by Southern Company and its subsidiaries, including Alabama Power, have been filed with the EPA. Challenges to the final rule have also been filed in the U.S. District Court of Appeals for the District of Columbia by numerous states, environmental organizations, industry groups, and others. The impact of the MATS rule will depend on the outcome of these and any other legal challenges and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Byproducts" of Alabama Power in Item 7 of the Form 10-K for additional information. On April 5, 2012, 10 environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts as soon as possible. Other parties are expected to file similar challenges. The ultimate outcome of this matter cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Alabama Power in Item 7 of the Form 10-K for additional information. On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. As proposed, the standards would not apply to existing units. The EPA has delayed its plans to propose greenhouse gas emissions performance standards for modified sources and emissions guidelines for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

PSC Matters

Retail Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Alabama Power in Item 7 and Note 3 to the financial statements of Alabama Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for information regarding Alabama Power's fuel cost recovery. Alabama Power's under recovered fuel costs as of March 31, 2012 totaled $6 million as compared to $31 million at December 31, 2011. These under recovered fuel costs at March 31, 2012 are included in deferred under recovered regulatory clause revenues on Alabama Power's Condensed Balance Sheets herein. This classification is based on an estimate which includes such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Income Tax Matters

Bonus Depreciation

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Alabama Power through 2013. Consequently, Alabama Power's positive cash flow benefit is estimated to be between $85 million and $110 million in 2012.

Other Matters

Alabama Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Alabama Power is subject to certain claims and legal actions arising in the ordinary course of business. Alabama Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against Alabama Power cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Alabama Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Alabama Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Other Matters" of Alabama Power in Item 7 of the Form 10-K for additional information regarding the earthquake and tsunami that struck Japan in March 2011. On March 12, 2012, the NRC issued three orders and a request for information based on the NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. The staff of the NRC expects to issue additional implementation guidance by August 2012. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time. See RISK FACTORS of Alabama Power in Item 1A of the Form 10-K for a discussion of certain risks associated with the operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Alabama Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Alabama Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Alabama Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Alabama Power in Item 7 of the Form 10-K for a complete discussion of Alabama Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Alabama Power in Item 7 of the Form 10-K for additional information. Alabama Power's financial condition remained stable at March 31, 2012. Alabama Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $140 million for the first three months of 2012, a decrease of $187 million as compared to the first three months of 2011. The decrease in cash provided from operating activities was primarily due to the timing of income tax payments and refunds, an increase in fossil fuel stock, and a decrease in deferred income taxes. The decrease was partially offset by an increase in receivables. Net cash used for investing activities totaled $235 million for the first three months of 2012 primarily due to gross property additions related to nuclear fuel and transmission, distribution, other production, and steam generation equipment. Net cash provided by financing activities totaled $106 million for the first three months of 2012. This was primarily due to the issuances of senior notes, partially offset by the payment of common stock dividends. Fluctuations in cash flow from financing activities vary year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for the first three months of 2012 include increases of $250 million of securities due within one year, $86 million in property, plant, and equipment associated with routine property additions and nuclear fuel, and $81 million in fossil fuel stock, at average cost, and a decrease of $97 million in other accounts payable.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Alabama Power in Item 7 of the Form 10-K for a description of Alabama Power's capital requirements for its construction program, scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, and trust funding requirements. Approximately $750 million will be required through March 31, 2013 to fund maturities and announced redemptions of long-term debt.

ALABAMA POWER COMPANY
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The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Alabama Power plans to obtain the funds required for construction and other purposes from sources similar to those utilized in the past. Alabama Power has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Alabama Power in Item 7 of the Form 10-K for additional information.

Alabama Power's current liabilities sometimes exceed current assets because of Alabama Power's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At March 31, 2012, Alabama Power had approximately $355 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2012 were as follows:

Expires					Executable Term Loans		Due Within One Year [(a)]	
2012	2013	2014 and Beyond	Total	Unused	One Year	Two Year	Term Out	No Term Out
	(in millions)		*(in millions)*		*(in millions)*		*(in millions)*	
$121	$35	$1,150	$1,306	$1,306	$51	$—	$51	$71

(a) Reflects facilities expiring on or before March 31, 2013.

See Note 6 to the financial statements of Alabama Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of Alabama Power. Alabama Power is currently in compliance with all such covenants. Alabama Power expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to Alabama Power's commercial paper borrowings and variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2012 was approximately $793 million.

Alabama Power may meet short-term cash needs through its commercial paper program. Alabama Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Alabama Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Alabama Power are loaned directly to Alabama Power. The obligations of each traditional operating company under these arrangements are several and there is no cross affiliate credit support.

Alabama Power had no commercial paper or short-term debt outstanding during the three-months ended March 31, 2012.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Alabama Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At March 31, 2012, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $310 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Alabama Power's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Alabama Power's market risk exposure relative to interest rate changes for the first quarter 2012 has not changed materially compared to the December 31, 2011 reporting period. Since a significant portion of outstanding indebtedness remains at fixed rates, Alabama Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Alabama Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Alabama Power enters into physical fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. Alabama Power continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. As such, Alabama Power had no material change in market risk exposure for the first quarter 2012 when compared with the December 31, 2011 reporting period.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2012 were as follows:

	First Quarter 2012 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(48)
Contracts realized or settled	13
Current period changes [(a)]	(18)
Contracts outstanding at the end of the period, assets (liabilities), net	$(53)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the three months ended March 31, 2012 was a decrease of $5 million, of which $3 million related to natural gas swaps and $2 million related to natural gas options. The change is attributable to both the volume of mmBtu and the price of natural gas. At March 31, 2012, Alabama Power had a net hedge volume of 37 million mmBtu, which consisted of 27 million mmBtu of swaps and 10 million mmBtu of options. The weighted average swap contract cost was approximately $1.72 per mmBtu above market prices. At December 31, 2011, Alabama Power had a net hedge volume of 39 million mmBtu, which consisted of 30 million mmBtu of swaps and 9 million mmBtu of options. The weighted average swap contract cost was approximately $1.45 per mmBtu above market prices. The change in option premiums is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All of the natural gas hedge gains and losses are recovered through Alabama Power's fuel cost recovery clause.

Regulatory hedges relate to Alabama Power's fuel-hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through Alabama Power's fuel cost recovery clause.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2012 and 2011 for energy-related derivative contracts that are not hedges were not material.

Alabama Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2012 were as follows:

	March 31, 2012 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$—	$—
Level 2	(53)	(42)	(11)	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(53)	$(42)	$(11)	$—

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by Alabama Power. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until all relevant regulations are finalized.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Alabama Power in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Alabama Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

In January 2012, Alabama Power issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including Alabama Power's continuous construction program. Alabama Power settled $100 million of interest rate swaps related to this issuance at a loss of $1 million. The loss is being amortized to interest expense, in earnings, over 10 years.

In March 2012, Alabama Power redeemed approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008.

Subsequent to March 31, 2012, Alabama Power redeemed $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Alabama Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(in millions)	
Operating Revenues:		
Retail revenues	**$ 1,594**	$ 1,815
Wholesale revenues, non-affiliates	**66**	83
Wholesale revenues, affiliates	**3**	11
Other revenues	**82**	80
Total operating revenues	**1,745**	1,989
Operating Expenses:		
Fuel	**440**	677
Purchased power, non-affiliates	**93**	74
Purchased power, affiliates	**159**	163
Other operations and maintenance	**434**	422
Depreciation and amortization	**188**	173
Taxes other than income taxes	**87**	87
Total operating expenses	**1,401**	1,596
Operating Income	**344**	393
Other Income and (Expense):		
Allowance for equity funds used during construction	**13**	25
Interest expense, net of amounts capitalized	**(91)**	(96)
Other income (expense), net	**(3)**	(1)
Total other income and (expense)	**(81)**	(72)
Earnings Before Income Taxes	**263**	321
Income taxes	**92**	111
Net Income	**171**	210
Dividends on Preferred and Preference Stock	**4**	4
Net Income After Dividends on Preferred and Preference Stock	**$ 167**	$ 206

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(in millions)	
Net Income After Dividends on Preferred and Preference Stock	**$ 167**	$ 206
Other comprehensive income (loss):		
Qualifying hedges:		
Reclassification adjustment for amounts included in net income, net of tax of $- and $-, respectively	**1**	1
Comprehensive Income	**$ 168**	$ 207

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

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GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(in millions)	
Operating Activities:		
Net income	**$ 171**	$ 210
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**229**	210
Deferred income taxes	**38**	56
Allowance for equity funds used during construction	**(13)**	(25)
Other, net	**33**	(14)
Changes in certain current assets and liabilities —		
-Receivables	**258**	122
-Fossil fuel stock	**(122)**	(30)
-Prepaid income taxes	**10**	80
-Other current assets	**(4)**	(14)
-Accounts payable	**(62)**	(50)
-Accrued taxes	**(206)**	(194)
-Accrued compensation	**(80)**	(65)
-Other current liabilities	**60**	64
Net cash provided from operating activities	**312**	350
Investing Activities:		
Property additions	**(476)**	(513)
Nuclear decommissioning trust fund purchases	**(287)**	(830)
Nuclear decommissioning trust fund sales	**285**	827
Cost of removal, net of salvage	**(15)**	1
Change in construction payables, net of joint owner portion	**(203)**	93
Other investing activities	**15**	(6)
Net cash used for investing activities	**(681)**	(428)
Financing Activities:		
Increase (decrease) in notes payable, net	**99**	(62)
Proceeds —		
Capital contributions from parent company	**9**	171
Pollution control revenue bonds issuances	**—**	137
Senior notes issuances	**750**	300
Other long-term debt issuances	**—**	250
Redemptions —		
Pollution control revenue bonds	**—**	(84)
Senior notes	**—**	(101)
Other long-term debt	**(250)**	(300)
Payment of preferred and preference stock dividends	**(4)**	(4)
Payment of common stock dividends	**(227)**	(224)
Other financing activities	**(8)**	(2)
Net cash provided from financing activities	**369**	81
Net Change in Cash and Cash Equivalents	**—**	3
Cash and Cash Equivalents at Beginning of Period	**13**	8
Cash and Cash Equivalents at End of Period	**$ 13**	$ 11
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (net of $6 and $9 capitalized for 2012 and 2011, respectively)	**$ 58**	$ 65
Income taxes (net of refunds)	**28**	(77)
Noncash transactions — accrued property additions at end of period	**178**	350

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

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GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2012	At December 31, 2011
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 13**	$ 13
Receivables —		
Customer accounts receivable	**490**	571
Unbilled revenues	**166**	172
Under recovered regulatory clause revenues	**—**	137
Joint owner accounts receivable	**59**	87
Other accounts and notes receivable	**45**	61
Affiliated companies	**35**	26
Accumulated provision for uncollectible accounts	**(12)**	(13)
Fossil fuel stock, at average cost	**844**	723
Materials and supplies, at average cost	**400**	406
Vacation pay	**84**	82
Prepaid income taxes	**122**	71
Other regulatory assets, current	**118**	108
Other current assets	**84**	106
Total current assets	**2,448**	2,550
Property, Plant, and Equipment:		
In service	**27,884**	27,804
Less accumulated provision for depreciation	**10,294**	10,296
Plant in service, net of depreciation	**17,590**	17,508
Other utility plant, net	**54**	55
Nuclear fuel, at amortized cost	**468**	443
Construction work in progress	**3,456**	3,274
Total property, plant, and equipment	**21,568**	21,280
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**62**	63
Nuclear decommissioning trusts, at fair value	**692**	667
Miscellaneous property and investments	**45**	44
Total other property and investments	**799**	774
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**757**	756
Other regulatory assets, deferred	**1,562**	1,604
Other deferred charges and assets	**203**	187
Total deferred charges and other assets	**2,522**	2,547
Total Assets	**$ 27,337**	$ 27,151

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	At March 31, 2012	At December 31, 2011
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 855**	$ 455
Notes payable	**614**	515
Accounts payable —		
Affiliated	**287**	337
Other	**470**	686
Customer deposits	**222**	213
Accrued taxes —		
Accrued income taxes	**47**	36
Unrecognized tax benefits	**9**	14
Other accrued taxes	**89**	304
Accrued interest	**119**	92
Accrued vacation pay	**60**	60
Accrued compensation	**47**	125
Liabilities from risk management activities	**80**	68
Other regulatory liabilities, current	**84**	65
Nuclear decommissioning trust securities lending collateral	**12**	32
Other current liabilities	**144**	139
Total current liabilities	**3,139**	3,141
Long-term Debt	**8,117**	8,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**4,491**	4,388
Deferred credits related to income taxes	**120**	122
Accumulated deferred investment tax credits	**217**	220
Employee benefit obligations	**901**	905
Asset retirement obligations	**745**	734
Other cost of removal obligations	**105**	110
Other deferred credits and liabilities	**254**	224
Total deferred credits and other liabilities	**6,833**	6,703
Total Liabilities	**18,089**	17,862
Preferred Stock	**45**	45
Preference Stock	**221**	221
Common Stockholder's Equity:		
Common stock, without par value—		
Authorized - 20,000,000 shares		
Outstanding - 9,261,500 shares	**398**	398
Paid-in capital	**5,540**	5,522
Retained earnings	**3,052**	3,112
Accumulated other comprehensive loss	**(8)**	(9)
Total common stockholder's equity	**8,982**	9,023
Total Liabilities and Stockholder's Equity	**$ 27,337**	$ 27,151

The accompanying notes as they relate to Georgia Power are an integral part of these condensed financial statements.

GEORGIA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRST QUARTER 2012 vs. FIRST QUARTER 2011

OVERVIEW

Georgia Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Georgia Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, and fuel prices. In addition, Georgia Power is currently constructing two new nuclear units and one new combined cycle generating unit. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Georgia Power for the foreseeable future.

Georgia Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Key Performance Indicators" of Georgia Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(39)	(18.9)

Georgia Power's net income after dividends on preferred and preference stock for the first quarter 2012 was $167 million compared to $206 million for the corresponding period in 2011. The decrease was primarily due to a decrease in operating revenues as a result of milder weather, higher depreciation and operations and maintenance expense, and lower AFUDC, partially offset by an increase related to retail revenue rate effects and lower income taxes in the first quarter 2012.

Retail Revenues

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(221)	(12.2)

In the first quarter 2012, retail revenues were $1.59 billion compared to $1.82 billion for the corresponding period in 2011.

Details of the change to retail revenues were as follows:

	First Quarter 2012	
	(in millions)	*(% change)*
Retail — prior year	$ 1,815	
Estimated change in —		
Rates and pricing	22	1.2
Sales growth (decline)	(7)	(0.4)
Weather	(50)	(2.8)
Fuel cost recovery	(186)	(10.2)
Retail – current year	$ 1,594	(12.2)%

Revenues associated with changes in rates and pricing increased in the first quarter 2012 when compared to the corresponding period in 2011 due to the rate pricing effect of decreased customer usage and the NCCR and demand-side management tariff increases effective January 1, 2012, as approved by the Georgia PSC, partially offset by lower contributions from market-driven rates from commercial and industrial customers.

Revenues attributable to changes in sales decreased in the first quarter 2012 when compared to the corresponding period in 2011. Weather-adjusted commercial and industrial KWH sales decreased 2.4% and 0.2%, respectively, in the first quarter 2012 when compared to the corresponding period in 2011, while weather-adjusted residential KWH sales remained flat. The economy continues to impact commercial sales.

Revenues resulting from changes in weather decreased in the first quarter 2012 when compared to the corresponding period in 2011 due to mild weather in the first quarter 2012 and cold weather in January 2011.

Fuel revenues and costs are allocated between retail and wholesale jurisdictions. Retail fuel cost recovery revenues decreased by $186 million in the first quarter of 2012 when compared to the corresponding period in 2011 due to decreased KWH energy sales and lower fuel costs. See "Fuel and Purchased Power Expenses" herein for additional information.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power costs, and do not affect net income.

Wholesale Revenues – Non-Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(17)	(20.5)

Wholesale revenues from sales to non-affiliates consist of PPAs and short-term opportunity sales. Wholesale revenues from PPAs have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Georgia Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above Georgia Power's variable cost of energy.

GEORGIA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

In the first quarter 2012, wholesale revenues from non-affiliates were $66 million compared to $83 million in the corresponding period in 2011, primarily due to a $20 million decrease in energy revenues, partially offset by a $3 million increase in capacity revenues. The decrease in the first quarter 2012 was primarily due to a 41.3% decrease in KWH sales due to lower demand resulting from mild weather in the first quarter 2012 and cold weather in January 2011.

Wholesale Revenues — Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(8)	(72.7)

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost.

In the first quarter 2012, wholesale revenues from affiliates were $3 million compared to $11 million in the corresponding period in 2011. The decrease was primarily due to a 59.5% decrease in KWH sales due to lower demand resulting from milder weather and the availability of market energy at a lower cost than Georgia Power-owned generation.

Fuel and Purchased Power Expenses

	First Quarter 2012 vs. First Quarter 2011	
	(change in millions)	*(% change)*
Fuel	$ (237)	(35.0)
Purchased power — non-affiliates	19	25.7
Purchased power — affiliates	(4)	(2.5)
Total fuel and purchased power expenses	$ (222)	

In the first quarter 2012, total fuel and purchased power expenses were $692 million compared to $914 million in the corresponding period in 2011. The decrease was primarily due to the lower cost of natural gas used for generation and lower demand related to mild weather in the first quarter 2012 compared to cold weather in January 2011.

Fuel and purchased power energy transactions do not have a significant impact on earnings since energy expenses are generally offset by energy revenues through Georgia Power's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Fuel Cost Recovery" herein for additional information.

GEORGIA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Details of Georgia Power's generation and purchased power were as follows:

	First Quarter 2012	First Quarter 2011
Total generation *(billions of KWHs)*	**13**	16
Total purchased power *(billions of KWHs)*	**8**	6
Sources of generation *(percent)* —		
Coal	**42**	62
Nuclear	**30**	23
Gas	**26**	12
Hydro	**2**	3
Cost of fuel, generated *(cents per net KWH)* —		
Coal	**4.67**	4.74
Nuclear	**0.86**	0.68
Gas	**3.16**	4.37
Average cost of fuel, generated *(cents per net KWH)*	**3.10**	3.73
Average cost of purchased power *(cents per net KWH)* *	**3.86**	5.57

* Average cost of purchased power includes fuel purchased by Georgia Power for tolling agreements where power is generated by the provider.

Fuel

In the first quarter 2012, fuel expense was $440 million compared to $677 million in the corresponding period in 2011. The decrease was due to a 22.1% decrease of KWHs generated as a result of lower KWH demand and a 16.9% decrease in the average cost of fuel per KWH generated primarily due to lower natural gas prices.

Purchased Power – Non-Affiliates

In the first quarter 2012, purchased power expense from non-affiliates was $93 million compared to $74 million in the corresponding period in 2011. The increase was due to a 139.8% increase in KWHs purchased as the market cost of available energy was lower than the additional Georgia Power-owned generation available, partially offset by a decrease of 47.9% in the average cost per KWH purchased.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Other Operations and Maintenance Expenses

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$12	2.8

In the first quarter 2012, other operations and maintenance expenses were $434 million compared to $422 million in the corresponding period in 2011. The increase was primarily due to a $10 million increase in employee pension expense, a $5 million increase in customer assistance expense, and a $2 million increase in nuclear property insurance, partially offset by an $8 million decrease in power generation expense due to outage timing and scope of outage work performed and a decrease in KWH generated as a result of lower demand due to milder weather in the first quarter 2012.

Depreciation and Amortization

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$15	8.7

In the first quarter 2012, depreciation and amortization was $188 million compared to $173 million in the corresponding period in 2011. The increase was primarily due to a $12 million increase in depreciation on additional plant in service related to new generation at Plant McDonough Unit 4 that went into service in December 2011, as well as additional transmission, distribution, and environmental projects.

Allowance for Equity Funds Used During Construction

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(12)	(48.0)

In the first quarter 2012, AFUDC equity was $13 million compared to $25 million in the corresponding period in 2011. The decrease was due to the completion of Plant McDonough Unit 4 in December 2011.

Interest Expense, Net of Amounts Capitalized

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(5)	(5.2)

In the first quarter 2012, interest expense, net of amounts capitalized was $91 million compared to $96 million for the corresponding period in 2011. The decrease for the first quarter 2012 when compared to the corresponding period in 2011 was primarily due to lower interest expense on existing variable rate pollution control revenue bonds.

Income Taxes

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(19)	(17.1)

In the first quarter 2012, income taxes were $92 million compared to $111 million in the corresponding period in 2011 due to lower pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Georgia Power's future earnings potential. The level of Georgia Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Georgia Power's business of selling electricity. These factors include Georgia Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Georgia Power's service territory. Changes in economic conditions impact sales for Georgia Power and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Georgia Power in Item 7 of the Form 10-K.

GEORGIA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – New Source Review Actions" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K for additional information. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power. At the same time, the EPA asked the U.S. Court of Appeals for the Eleventh Circuit to stay its appeal of the judgment in favor of Alabama Power. Alabama Power filed oppositions to the EPA's motion and its request for a stay. On March 29, 2012, the U.S. Court of Appeals for the Eleventh Circuit denied the EPA's request to stay its appeal. The U.S. District Court for the Northern District of Alabama has not ruled on the EPA's motion seeking vacatur of the judgment. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Hurricane Katrina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Climate Change Litigation – Hurricane Katrina Case" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Environmental Matters – Climate Change Litigation – Hurricane Katrina Case" in Item 8 of the Form 10-K for additional information. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the amended class action complaint filed on May 27, 2011 by the plaintiffs. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – General" of Georgia Power in Item 7 of the Form 10-K for information regarding Georgia Power's estimated base level capital expenditures to comply with existing statutes and regulations for 2012 through 2014, as well as Georgia Power's preliminary estimates for potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) and the EPA's proposed water and coal combustion byproducts rules. Georgia Power is continuing to develop its compliance strategy and to assess the potential costs of complying with the MATS rule and the EPA's proposed water and coal combustion byproducts rules.

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Georgia Power's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including any proposed environmental regulations; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and Georgia Power's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. Georgia Power's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

As part of Southern Electric Generating Company's (SEGCO) environmental compliance strategy, the Board of Directors of SEGCO approved adding natural gas as the primary fuel source in 2015 for its 1,000 MWs of generating capacity and the construction of the necessary natural gas pipeline. SEGCO is jointly owned by Georgia Power and Alabama Power. The capacity of SEGCO's units is sold to Georgia Power and Alabama Power through a PPA. See Note 4 to the financial statements of Georgia Power in Item 8 of the Form 10-K for additional information. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material impact on Georgia Power's financial statements.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Georgia Power in Item 7 of the Form 10-K for additional information on the eight-hour ozone air quality standards and the MATS rule.

On May 1, 2012, the EPA released its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. The only area within Georgia Power's service territory designated as a nonattainment area was a 15-county area within metropolitan Atlanta.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by Southern Company and its subsidiaries, including Georgia Power, have been filed with the EPA. Challenges to the final rule have also been filed in the U.S. District Court of Appeals for the District of Columbia by numerous states, environmental organizations, industry groups, and others. The impact of the MATS rule will depend on the outcome of these and any other legal challenges and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Byproducts" of Georgia Power in Item 7 of the Form 10-K for additional information. On April 5, 2012, 10 environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts as soon as possible. Other parties are expected to file similar challenges. The ultimate outcome of this matter cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Georgia Power in Item 7 of the Form 10-K for additional information. On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. As proposed, the standards would not apply to existing units. The EPA has delayed its plans to propose greenhouse gas emissions performance standards for modified sources and emissions guidelines for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

PSC Matters

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Fuel Cost Recovery" in Item 8 of the Form 10-K for additional information. As of March 31, 2012, Georgia Power had a total over recovered fuel cost balance of approximately $22 million compared to an under recovered balance of $137 million at December 31, 2011. The over recovered fuel costs at March 31, 2012 are included in other deferred credits and liabilities on Georgia Power's Condensed Balance Sheet herein. The under recovered fuel costs at December 31, 2011 are included in current assets on Georgia Power's Condensed Balance Sheet herein. Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, any changes in the billing factor will not have a significant effect on Georgia Power's revenues or net income, but will affect cash flow.

On March 30, 2012, Georgia Power filed a request with the Georgia PSC to decrease fuel rates by 19%, which is expected to reduce annual billings by $567 million. The decrease in fuel costs is driven primarily by lower natural gas prices as a result of increased natural gas supplies. The Georgia PSC is scheduled to vote on this matter on June 21, 2012. As proposed, the rate decrease would become effective July 1, 2012; however, Georgia Power is currently working with the Georgia PSC to potentially implement the proposed decrease effective June 1, 2012. The ultimate outcome of this matter cannot be determined at this time.

2011 Integrated Resource Plan Update

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans" and "– 2011 Integrated Resource Plan Update" in Item 8 of the Form 10-K for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; the 2010 ARP; and the 2011 IRP Update.

On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire two coal-fired generation units at Plant Branch as of October 31, 2013 and December 31, 2013 and an oil-fired unit at Plant Mitchell as of March 26, 2012, which was included in Georgia Power's 2011 IRP Update. The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. The PPAs remain subject to FERC approval. The ultimate outcome of this matter cannot be determined at this time.

Income Tax Matters

Bonus Depreciation

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Georgia Power through 2013. Consequently, Georgia Power's positive cash flow benefit is estimated to be between $320 million and $420 million in 2012.

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Construction

Nuclear

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Construction – Nuclear" in Item 8 of the Form 10-K for additional information regarding the construction of Plant Vogtle Units 3 and 4.

On February 16, 2012, a group of petitioners who had intervened in the NRC's combined construction and operating licenses (COLs) proceedings for Plant Vogtle Units 3 and 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the NRC's issuance of the COLs. In addition, on February 16, 2012, another group of petitioners filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's certification of the Westinghouse Design Certification Document, as amended (DCD). On April 3, 2012, the U.S. Court of Appeals for the District of Columbia Circuit granted a motion filed by these two groups of petitioners to consolidate their challenges. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the order issuing the COLs for Plant Vogtle Units 3 and 4 with the U.S. District Court for the District of Columbia. Georgia Power has filed a motion to intervene in these proceedings and intends to vigorously contest these petitions.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related CWIP accounts in rate base. Also in 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows Georgia Power to recover financing costs for nuclear construction projects by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows Georgia Power to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered Georgia Power to report against this total certified cost of approximately $6.1 billion. In addition, in December 2010, the Georgia PSC approved Georgia Power's NCCR tariff. The NCCR tariff became effective January 1, 2011 and adjustments are filed with the Georgia PSC on November 1 of each year to become effective on January 1 of the following year. Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At March 31, 2012, approximately $68 million of these 2009 and 2010 costs remained in CWIP.

Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners) and Westinghouse and Stone & Webster, Inc. (collectively, Consortium) have established both informal and formal dispute resolution procedures in accordance with the engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 MWs each and related facilities, structures, and improvements at Plant Vogtle entered into by the parties (Vogtle 3 and 4 Agreement) in order to resolve issues arising during the course of constructing a project of this magnitude. The Consortium and Georgia Power (on behalf of the Owners) have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including costs associated with design changes to the DCD, and costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs. The Owners and the Consortium have begun negotiations regarding these issues, including the assertion by the Consortium that the Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. In preliminary discussions, the Consortium has provided its initial estimate of its proposed adjustment to the contract price. The Consortium's estimated adjustment attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $400 million (in 2008 dollars) with respect to these issues, which include an initial estimate of costs for efforts to maintain the projected in-service dates of 2016 and 2017 for Plant Vogtle Units 3 and 4, respectively. Georgia Power has not agreed with the amount of these proposed adjustments or that the Owners have responsibility for any costs related to these issues. Georgia Power expects negotiations with the Consortium to continue over the next several months during which time the parties will attempt to reach a mutually acceptable compromise of their positions. If a compromise cannot be reached, formal dispute resolution, including litigation, may follow. Georgia Power intends to vigorously defend its positions. If these costs are imposed upon the Owners, Georgia Power would seek an amendment to the certified cost of Plant Vogtle Units 3 and 4, if necessary. Additional claims by the Consortium or Georgia Power (on behalf of the Owners) are expected to arise throughout the construction of Plant Vogtle Units 3 and 4.

In addition, there are processes in place to assure compliance with the design requirements specified in the DCD and the COLs, including rigorous inspection by Southern Nuclear and the NRC that occurs throughout construction. A recent routine NRC inspection identified that certain details of the rebar construction in the Plant Vogtle Unit 3 nuclear island were not consistent with the DCD. Georgia Power expects to receive official notice of these findings from the NRC. Georgia Power, on behalf of the Owners, is currently engaged in constructive discussions with the Consortium to identify appropriate corrective actions. Various inspection issues are expected as construction proceeds.

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including legal challenges to the NRC issuance of the COLs and certification of the DCD. Similar additional challenges at the state and federal level are expected as construction proceeds.

See RISK FACTORS of Georgia Power in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world.

The ultimate outcome of these matters cannot be determined at this time.

Other Construction

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction – Other Construction" of Georgia Power in Item 7 and Note 3 to the financial statements of Georgia Power under "Construction – Other Construction" in Item 8 of the Form 10-K for additional information.

Georgia Power placed Plant McDonough Unit 5 into service on April 26, 2012. Plant McDonough Unit 6 is expected to be placed into service in November 2012. Plant McDonough Unit 1 was retired on February 29, 2012.

Other Matters

Georgia Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Georgia Power is subject to certain claims and legal actions arising in the ordinary course of business. Georgia Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against Georgia Power cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Georgia Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Georgia Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Other Matters" of Georgia Power in Item 7 of the Form 10-K for additional information regarding the earthquake and tsunami that struck Japan in March 2011. On March 12, 2012, the NRC issued three orders and a request for information based on the NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. The staff of the NRC expects to issue additional implementation guidance by August 2012. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time. See RISK FACTORS of Georgia Power in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Georgia Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Georgia Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Georgia Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" of Georgia Power in Item 7 of the Form 10-K for a complete discussion of Georgia Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, and Pension and Other Postretirement Benefits.

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FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Georgia Power in Item 7 of the Form 10-K for additional information. Georgia Power's financial condition remained stable at March 31, 2012. Georgia Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $312 million for the first three months of 2012 compared to $350 million for the corresponding period in 2011. The $38 million decrease is primarily due to lower retail operating revenues and higher fuel inventory additions in the first quarter 2012. Net cash used for investing activities totaled $681 million primarily due to gross property additions to utility plant in the first three months of 2012. Net cash provided from financing activities totaled $369 million for the first three months of 2012 compared to $81 million for the corresponding period in 2011. The $288 million increase is primarily due to increased debt issuances in the first quarter 2012.

Significant balance sheet changes for the first three months of 2012 include increases of $288 million in total property, plant, and equipment and $121 million in fossil fuel stock, as well as the elimination of $137 million in under recovered fuel.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Georgia Power in Item 7 of the Form 10-K for a description of Georgia Power's capital requirements for its construction program, scheduled maturities of long-term debt, as well as related interest, derivative obligations, preferred and preference stock dividends, leases, purchase commitments, trust funding requirements, and unrecognized tax benefits. Approximately $855 million will be required through March 31, 2013 to fund maturities of long-term debt.

On March 20, 2012, the Georgia PSC approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. However, these PPAs remain subject to FERC approval. See FUTURE EARNINGS POTENTIAL – "PSC Matters – 2011 Integrated Resource Plan Update" herein for additional information. These PPAs will be accounted for as leases and are expected to result in additional obligations of approximately $56 million in 2015, $66 million in 2016, and a total of $973 million thereafter. The ultimate outcome of this matter cannot be determined at this time.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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Sources of Capital

Except as described below with respect to potential DOE loan guarantees, Georgia Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Georgia Power in Item 7 of the Form 10-K for additional information.

In June 2010, Georgia Power reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by Georgia Power related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. There can be no assurance that the DOE will issue loan guarantees for Georgia Power. See FUTURE EARNINGS POTENTIAL – "Construction – Nuclear" herein for more information on Plant Vogtle Units 3 and 4.

Georgia Power's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At March 31, 2012, Georgia Power had approximately $13 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2012 were as follows:

Expires					Executable Term Loans		Due Within One Year (a)	
							Term	No Term
2012	2013	2014 and Beyond	Total	Unused	One Year	Two Year	Out	Out
	(in millions)		*(in millions)*		*(in millions)*		*(in millions)*	
$—	$—	$1,750	$1,750	$1,745	$—	$—	$—	$—

(a) Reflects facilities expiring on or before March 31, 2013.

See Note 6 to the financial statements of Georgia Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of Georgia Power. Georgia Power is currently in compliance with all such covenants. Georgia Power expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to Georgia Power's commercial paper borrowings and variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2012 was approximately $868 million.

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Georgia Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Georgia Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Georgia Power are loaned directly to Georgia Power. The obligations of each traditional operating company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings, excluding $2 million of notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
March 31, 2012:					
Commercial paper	$ 312	0.3%	$ 229	0.2%	$ 517
Short-term bank debt	300	1.1%	290	1.2%	300
Total	$ 612	0.7%	$ 519	0.8%	

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Credit Rating Risk

Georgia Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at March 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 68
Below BBB- and/or Baa3	1,540

Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Georgia Power's ability to access capital markets, particularly the short-term debt market.

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Market Price Risk

Georgia Power's market risk exposure relative to interest rate changes for the first quarter 2012 has not changed materially compared with the December 31, 2011 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Georgia Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Georgia Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Georgia Power enters into physical fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. Georgia Power continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. As such, Georgia Power had no material change in market risk exposure for the first quarter 2012 relative to fuel and electricity prices when compared with the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2012 were as follows:

	First Quarter 2012 Changes
	Fair Value *(in millions)*
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(82)
Contracts realized or settled	19
Current period changes [(a)]	(23)
Contracts outstanding at the end of the period, assets (liabilities), net	$(86)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the three months ended March 31, 2012 was a decrease of $4 million, of which $8 million related to a decrease from natural gas options, partially offset by an increase of $4 million from natural gas swaps. The change is attributable to both the volume of mmBtu and the price of natural gas. At March 31, 2012, Georgia Power had a net hedge volume of 85 million mmBtu, which consisted of 25 million mmBtu of swaps and 60 million mmBtu of options. The weighted average swap contract cost was approximately $2.13 per mmBtu above market prices. At December 31, 2011, Georgia Power had a net hedge volume of 73 million mmBtu, which consisted of 29 million mmBtu of swaps and 44 million mmBtu of options. The weighted average swap contract cost was approximately $1.65 per mmBtu above market prices. The change in option premiums is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through Georgia Power's fuel cost recovery mechanism.

Regulatory hedges relate to Georgia Power's fuel-hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through Georgia Power's fuel cost recovery mechanism.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2012 and 2011 for energy-related derivative contracts that are not hedges were not material.

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Georgia Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2012 were as follows:

	March 31, 2012 Fair Value Measurements		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(86)	(66)	(20)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(86)	$(66)	$(20)

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by Georgia Power. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until all relevant regulations are finalized.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Market Price Risk" of Georgia Power in Item 7 and Note 1 under "Financial Instruments" and Note 11 to the financial statements of Georgia Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

In January 2012, Georgia Power entered into a six-month floating rate bank loan in an aggregate amount of $100 million, bearing interest based on one-month LIBOR. The proceeds were used for general corporate purposes, including Georgia Power's continuous construction program.

In March 2012, Georgia Power issued $750 million aggregate principal amount of Series 2012A 4.30% Senior Notes due March 15, 2042. The proceeds were used to repay a portion of Georgia Power's short-term debt, to repay two bank loans, each in an aggregate principal amount of $125 million, and for general corporate purposes, including Georgia Power's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Georgia Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

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GULF POWER COMPANY

GULF POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in thousands)	
Operating Revenues:		
Retail revenues	**$ 238,520**	$ 274,826
Wholesale revenues, non-affiliates	**27,118**	31,019
Wholesale revenues, affiliates	**36,364**	4,135
Other revenues	**14,243**	14,628
Total operating revenues	**316,245**	324,608
Operating Expenses:		
Fuel	**121,088**	131,782
Purchased power, non-affiliates	**11,225**	7,003
Purchased power, affiliates	**2,513**	16,618
Other operations and maintenance	**75,230**	80,509
Depreciation and amortization	**33,307**	31,756
Taxes other than income taxes	**23,784**	24,896
Total operating expenses	**267,147**	292,564
Operating Income	**49,098**	32,044
Other Income and (Expense):		
Allowance for equity funds used during construction	**1,237**	2,135
Interest expense, net of amounts capitalized	**(15,368)**	(13,629)
Other income (expense), net	**(1,009)**	(549)
Total other income and (expense)	**(15,140)**	(12,043)
Earnings Before Income Taxes	**33,958**	20,001
Income taxes	**11,741**	6,759
Net Income	**22,217**	13,242
Dividends on Preference Stock	**1,551**	1,551
Net Income After Dividends on Preference Stock	**$ 20,666**	$ 11,691

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in thousands)	
Net Income After Dividends on Preference Stock	**$ 20,666**	$ 11,691
Other comprehensive income (loss):		
Qualifying hedges:		
Reclassification adjustment for amounts included in net income, net of tax of $90 and $90, respectively	**143**	143
Total other comprehensive income (loss)	**143**	143
Comprehensive Income	**$ 20,809**	$ 11,834

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in thousands)	
Operating Activities:		
Net income	**$ 22,217**	$ 13,242
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**34,844**	33,294
Deferred income taxes	**32,505**	6,249
Allowance for equity funds used during construction	**(1,237)**	(2,135)
Pension, postretirement, and other employee benefits	**1,315**	(1,256)
Stock based compensation expense	**685**	518
Other, net	**5,478**	(3,793)
Changes in certain current assets and liabilities —		
-Receivables	**14,754**	35,336
-Prepayments	**1,559**	1,156
-Fossil fuel stock	**1,543**	(14,941)
-Materials and supplies	**(1,476)**	(726)
-Prepaid income taxes	**17,324**	28,889
-Other current assets	**-**	7
-Accounts payable	**(21,516)**	(8,863)
-Accrued taxes	**(1,453)**	4,053
-Accrued compensation	**(9,190)**	(10,000)
-Over recovered regulatory clause revenues	**14,516**	687
-Other current liabilities	**5,637**	5,440
Net cash provided from operating activities	**117,505**	87,157
Investing Activities:		
Property additions	**(94,879)**	(94,239)
Cost of removal, net of salvage	**(9,342)**	(5,314)
Change in construction payables	**7,773**	3,171
Payments pursuant to long-term service agreements	**(2,274)**	(2,198)
Other investing activities	**(76)**	68
Net cash used for investing activities	**(98,798)**	(98,512)
Financing Activities:		
Decrease in notes payable, net	**(27,338)**	(6,620)
Proceeds —		
Common stock issued to parent	**40,000**	50,000
Capital contributions from parent company	**732**	809
Redemptions —		
Senior notes	**(16)**	(125)
Payment of preference stock dividends	**(1,551)**	(1,551)
Payment of common stock dividends	**(28,950)**	(27,500)
Other financing activities	**198**	110
Net cash provided from (used for) financing activities	**(16,925)**	15,123
Net Change in Cash and Cash Equivalents	**1,782**	3,768
Cash and Cash Equivalents at Beginning of Period	**17,328**	16,434
Cash and Cash Equivalents at End of Period	**$ 19,110**	$ 20,202
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (net of $493 and $851 capitalized for 2012 and 2011, respectively)	**$ 9,352**	$ 8,284
Income taxes (net of refunds)	**(35,742)**	(29,557)
Noncash transactions - accrued property additions at end of period	**28,788**	17,882

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

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GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2012	At December 31, 2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 19,110**	$ 17,328
Receivables —		
Customer accounts receivable	**54,868**	72,754
Unbilled revenues	**48,705**	49,921
Under recovered regulatory clause revenues	**4,536**	5,530
Other accounts and notes receivable	**11,546**	13,350
Affiliated companies	**19,986**	14,844
Accumulated provision for uncollectible accounts	**(1,433)**	(1,962)
Fossil fuel stock, at average cost	**146,023**	147,567
Materials and supplies, at average cost	**51,257**	49,781
Other regulatory assets, current	**44,521**	35,849
Prepaid expenses	**44,153**	28,327
Other current assets	**469**	2,051
Total current assets	**443,741**	435,340
Property, Plant, and Equipment:		
In service	**3,898,726**	3,846,446
Less accumulated provision for depreciation	**1,140,589**	1,124,291
Plant in service, net of depreciation	**2,758,137**	2,722,155
Construction work in progress	**333,631**	287,173
Total property, plant, and equipment	**3,091,768**	3,009,328
Other Property and Investments	**16,469**	16,394
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**49,453**	48,210
Other regulatory assets, deferred	**316,519**	323,116
Other deferred charges and assets	**29,433**	39,493
Total deferred charges and other assets	**395,405**	410,819
Total Assets	**$ 3,947,383**	$ 3,871,881

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	At March 31, 2012	At December 31, 2011
	(in thousands)	
Current Liabilities:		
Notes payable	**83,589**	114,507
Accounts payable —		
Affiliated	**45,716**	54,874
Other	**61,034**	63,265
Customer deposits	**36,010**	35,779
Accrued taxes —		
Accrued income taxes	**104**	1,362
Other accrued taxes	**11,712**	12,114
Accrued interest	**19,312**	14,018
Accrued compensation	**5,294**	14,485
Other regulatory liabilities, current	**45,436**	35,639
Liabilities from risk management activities	**30,811**	22,786
Other current liabilities	**23,104**	22,916
Total current liabilities	**362,122**	391,745
Long-term Debt	**1,235,586**	1,235,447
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**515,663**	458,978
Accumulated deferred investment tax credits	**6,422**	6,760
Employee benefit obligations	**109,589**	109,740
Other cost of removal obligations	**211,649**	214,598
Other regulatory liabilities, deferred	**45,300**	44,843
Other deferred credits and liabilities	**204,446**	186,824
Total deferred credits and other liabilities	**1,093,069**	1,021,743
Total Liabilities	**2,690,777**	2,648,935
Preference Stock	**97,998**	97,998
Common Stockholder's Equity:		
Common stock, without par value—		
Authorized - 20,000,000 shares		
Outstanding - March 31, 2012: 4,542,717 shares		
- December 31, 2011: 4,142,717 shares	**393,060**	353,060
Paid-in capital	**544,510**	542,709
Retained earnings	**223,049**	231,333
Accumulated other comprehensive loss	**(2,011)**	(2,154)
Total common stockholder's equity	**1,158,608**	1,124,948
Total Liabilities and Stockholder's Equity	**$ 3,947,383**	$ 3,871,881

The accompanying notes as they relate to Gulf Power are an integral part of these condensed financial statements.

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GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRST QUARTER 2012 vs. FIRST QUARTER 2011

OVERVIEW

Gulf Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Gulf Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel prices, and storm restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Gulf Power for the foreseeable future.

On March 12, 2012, the Florida PSC approved a permanent increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the permanent increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the permanent increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. Gulf Power's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to Gulf Power's retail base rates and charges of $4 million to be effective in January 2013. On April 18, 2012, Gulf Power filed a motion to reconsider one aspect of the decision dealing with property acquired as a potential site for a future generating plant. If the motion is granted, the previously approved rates would be increased by an additional $2 million. The ultimate outcome of this matter cannot be determined at this time.

Gulf Power continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS — OVERVIEW — "Key Performance Indicators" of Gulf Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$9.0	76.8

Gulf Power's net income after dividends on preference stock for the first quarter 2012 was $20.7 million compared to $11.7 million for the corresponding period in 2011. The increase was primarily due to an increase related to interim retail rate revenues, higher wholesale capacity revenues from non-affiliates, and a decrease in other operations and maintenance expenses in 2012, partially offset by milder weather in the first quarter 2012 compared to the corresponding period in 2011.

Retail Revenues

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(36.3)	(13.2)

In the first quarter 2012, retail revenues were $238.5 million compared to $274.8 million for the corresponding period in 2011.

GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Details of the change to retail revenues were as follows:

	First Quarter 2012	
	(in millions)	*(% change)*
Retail – prior year	$274.8	
Estimated change in –		
Rates and pricing	12.5	4.5
Sales growth (decline)	1.3	0.5
Weather	(8.3)	(3.0)
Fuel and other cost recovery	(41.8)	(15.2)
Retail – current year	$238.5	(13.2)%

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters" of Gulf Power in Item 7 and Note 1 to the financial statements of Gulf Power under "Revenues" and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters" in Item 8 of the Form 10-K for additional information regarding Gulf Power's retail base rate case and cost recovery clauses, including Gulf Power's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery.

Revenues associated with changes in rates and pricing increased in the first quarter 2012 when compared to the corresponding period in 2011 primarily due to an increase related to interim retail rate revenues and revenues associated with higher recoverable costs under Gulf Power's energy conservation cost recovery clause, partially offset by revenues associated with lower recoverable costs under Gulf Power's environmental cost recovery clause.

Revenues attributable to changes in sales increased in the first quarter 2012 when compared to the corresponding period in 2011. KWH energy sales to industrial customers decreased 6.8% primarily due to increased customer co-generation associated with the lower cost of natural gas in 2012 and changes in customer production levels. Weather-adjusted KWH energy sales to commercial customers increased 3.3% due to higher use per customer. Weather-adjusted KWH energy sales to residential customers remained relatively flat.

Revenues attributable to changes in weather decreased in the first quarter 2012 when compared to the corresponding period for 2011 due to milder weather in the first quarter 2012 compared to the corresponding period in 2011.

Fuel and other cost recovery revenues decreased in the first quarter 2012 when compared to the corresponding period for 2011 primarily due to revenues associated with lower recoverable fuel cost for generation and purchased power energy costs in addition to fewer KWH energy sales. Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Fuel Cost Recovery" herein for additional information.

Wholesale Revenues – Non-Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(3.9)	(12.6)

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Gulf Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation. Wholesale revenues from non-affiliates include unit power sales under long-term contracts to other utilities in Florida and Georgia.

GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Wholesale revenues from these contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost.

In the first quarter 2012, wholesale revenues from non-affiliates were $27.1 million compared to $31.0 million for the corresponding period in 2011. The decrease was primarily due to lower energy revenues related to a 58.4% decrease in KWH sales resulting primarily from less energy scheduled by unit power customers, partially offset by a 31.6% increase in capacity revenues related to increased capacity rates resulting from contract provisions. These contracts include change-in-law provisions that provide for recovery of the environmental costs related to the generating resource.

Wholesale Revenues – Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$32.3	779.4

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the fuel revenue related to energy sales and the cost of energy purchases are both included in the determination of recoverable fuel costs and are generally offset by revenues collected in Gulf Power's fuel cost recovery clause.

In the first quarter 2012, wholesale revenues from affiliates were $36.4 million compared to $4.1 million for the corresponding period in 2011. The increase was primarily due to higher energy revenues related to a 1,205% increase in KWH energy sales resulting from the availability of Gulf Power's lower priced natural gas resources to serve affiliate demand.

Fuel and Purchased Power Expenses

	First Quarter 2012 vs. First Quarter 2011	
	(change in millions)	*(% change)*
Fuel	$(10.7)	(8.1)
Purchased power – non-affiliates	4.2	60.3
Purchased power – affiliates	(14.1)	(84.9)
Total fuel and purchased power expenses	$(20.6)	

In the first quarter 2012, total fuel and purchased power expenses were $134.8 million compared to $155.4 million for the corresponding period in 2011. The net decrease in fuel and purchased power expenses was due to a $65.5 million decrease in the average cost of generated and purchased power and a $25.0 million decrease related to KWHs generated, partially offset by a $69.9 million increase related to KWHs purchased.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and purchased power expenses are generally offset by energy and capacity revenues through Gulf Power's fuel cost and purchased power capacity recovery clauses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Fuel Cost Recovery" and "– Purchased Power Capacity Recovery" herein for additional information.

GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Details of Gulf Power's generation and purchased power were as follows:

	First Quarter 2012	First Quarter 2011
Total generation *(millions of KWHs)*	**2,341**	2,801
Total purchased power *(millions of KWHs)*	**1,750**	448
Sources of generation *(percent)* –		
Coal	**53**	67
Gas	**47**	33
Cost of fuel, generated *(cents per net KWH)* –		
Coal	**4.29**	5.03
Gas	**3.44**	3.99
Average cost of fuel, generated *(cents per net KWH)*	**3.89**	4.69
Average cost of purchased power *(cents per net KWH)* *	**2.50**	5.37

* Average cost of purchased power includes fuel purchased by Gulf Power for tolling agreements where power is generated by the provider.

Fuel

In the first quarter 2012, fuel expense was $121.1 million compared to $131.8 million for the corresponding period in 2011. The decrease was primarily the result of a 13.8% decrease in the average cost of natural gas per KWH generated, a higher percentage of utilization of lower cost natural gas-fired sources, and a 16.5% decrease in KWHs generated as a result of lower demand. These decreases were partially offset by a 290.6% increase in KWHs purchased.

In the first quarter 2012, the decrease in the average cost of fuel was a result of decreases in the average costs of natural gas and coal per KWH generated and a higher percentage of utilization of Gulf Power's lower cost natural gas-fired generation sources.

Purchased Power – Non-Affiliates

In the first quarter 2012, purchased power expense from non-affiliates was $11.2 million compared to $7.0 million for the corresponding period in 2011. The increase was primarily due to a $4.2 million increase in energy costs resulting from a 1,957% increase in KWHs purchased.

In the first quarter 2012, the average cost of purchased power from non-affiliates was 2.4 cents per net KWH compared to 8.8 cents per net KWH for the corresponding period in 2011. The decrease was primarily the result of a decrease in the average cost of natural gas.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the first quarter 2012, purchased power expense from affiliates was $2.5 million compared to $16.6 million for the corresponding period in 2011. The decrease was primarily due to a $14.3 million decrease in energy costs resulting from a 95.2% decrease in KWHs purchased, partially offset by a $0.2 million increase in capacity costs.

In the first quarter 2012, the average cost of purchased power from affiliates was 14.5 cents per net KWH compared to 4.6 cents per net KWH for the corresponding period in 2011. The increase was primarily due to fewer KWHs purchased and increased capacity costs, partially offset by lower energy costs.

GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(5.3)	(6.6)

In the first quarter 2012, other operations and maintenance expenses were $75.2 million compared to $80.5 million for the corresponding period in 2011. The decrease was primarily due to an $11.4 million decrease in routine and planned outage maintenance expense at generation facilities, partially offset by increases of $3.5 million for labor and benefit-related expenses, $1.4 million in marketing programs, and $0.6 million in other energy services projects. The increased expense from energy service projects did not have a material impact on earnings since it was offset by associated revenues.

Depreciation and Amortization

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$1.5	4.9

In the first quarter 2012, depreciation and amortization was $33.3 million compared to $31.8 million for the corresponding period in 2011. The increase was primarily due to net additions to transmission and distribution facilities.

Taxes Other Than Income Taxes

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(1.1)	(4.5)

In the first quarter 2012, taxes other than income taxes were $23.8 million compared to $24.9 million for the corresponding period in 2011. The decrease was primarily due to a $2.0 million decrease in gross receipt taxes and franchise fees, which have no impact on net income, partially offset by a $0.4 million increase in property taxes and a $0.5 million increase in payroll taxes.

Allowance for Equity Funds Used During Construction

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(0.9)	(42.1)

In the first quarter 2012, AFUDC equity was $1.2 million compared to $2.1 million for the corresponding period in 2011. The decrease was primarily due to an adjustment related to deferred future generation carrying costs, partially offset by increases related to construction of environmental control projects at generating facilities.

GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Interest Expense, Net of Amounts Capitalized

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$1.8	12.8

In the first quarter 2012, interest expense, net of amounts capitalized was $15.4 million compared to $13.6 million for the corresponding period in 2011. The increase was primarily due to net increases in long-term debt.

Income Taxes

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$4.9	73.7

In the first quarter 2012, income taxes were $11.7 million compared to $6.8 million for the corresponding period in 2011. The increase was primarily due to higher pre-tax earnings, partially offset by a decrease in unrecognized tax benefits.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Gulf Power's future earnings potential. The level of Gulf Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Gulf Power's business of selling electricity. These factors include Gulf Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Gulf Power's service territory. Changes in economic conditions impact sales for Gulf Power, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL of Gulf Power in Item 7 of the Form 10-K.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

New Source Review Actions

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – New Source Review Actions" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Environmental Matters – New Source Review Actions" in Item 8 of the Form 10-K for additional information. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power. At the same time, the EPA asked the U.S. Court of Appeals for the Eleventh Circuit to stay its appeal of the judgment in favor of Alabama Power. Alabama Power filed oppositions to the EPA's motion and its request for a stay. On March 29, 2012, the U.S. Court of Appeals for the Eleventh Circuit denied the EPA's request to stay its appeal. The U.S. District Court for the Northern District of Alabama has not ruled on the EPA's motion seeking vacatur of the judgment. The ultimate outcome of this matter cannot be determined at this time.

Climate Change Litigation

Hurricane Katrina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Climate Change Litigation – Hurricane Katrina Case" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Environmental Matters – Climate Change Litigation – Hurricane Katrina Case" in Item 8 of the Form 10-K for additional information. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the amended class action complaint filed on May 27, 2011 by the plaintiffs. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – General" of Gulf Power in Item 7 of the Form 10-K for information regarding Gulf Power's estimated base level capital expenditures to comply with existing statutes and regulations for 2012 through 2014, as well as Gulf Power's preliminary estimates for potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) and the EPA's proposed water and coal combustion byproducts rules. Gulf Power is continuing to develop its compliance strategy and to assess the potential costs of complying with the MATS rule and the EPA's proposed water and coal combustion byproducts rules.

Gulf Power's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including any proposed environmental regulations; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and Gulf Power's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. Gulf Power's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" of Gulf Power in Item 7 of the Form 10-K for additional information on the eight-hour ozone air quality standards and the MATS rule.

On May 1, 2012, the EPA released its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. None of the areas within Gulf Power's service territory were designated as nonattainment areas.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by Southern Company and its subsidiaries, including Gulf Power, have been filed with the EPA. Challenges to the final rule have also been filed in the U.S. District Court of Appeals for the District of Columbia by numerous states, environmental organizations, industry groups, and others. The impact of the MATS rule will depend on the outcome of these and any other legal challenges and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Byproducts" of Gulf Power in Item 7 of the Form 10-K for additional information. On April 5, 2012, 10 environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts as soon as possible. Other parties are expected to file similar challenges. The ultimate outcome of this matter cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" of Gulf Power in Item 7 of the Form 10-K for additional information. On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. As proposed, the standards would not apply to existing units. The EPA has delayed its plans to propose greenhouse gas emissions performance standards for modified sources and emissions guidelines for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

PSC Matters

Retail Base Rate Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Base Rate Case" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Retail Base Rate Case" in Item 8 of the Form 10-K for additional information.

On March 12, 2012, the Florida PSC approved a permanent increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the permanent increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the permanent increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. Gulf Power's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to Gulf Power's retail base rates and charges of $4 million to be effective in January 2013. On April 18, 2012, Gulf Power filed a motion to reconsider one aspect of the decision dealing with property acquired as a potential site for a future generating plant. If the motion is granted, the previously approved rates would be increased by an additional $2 million. The ultimate outcome of this matter cannot be determined at this time.

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Cost Recovery Clauses

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Cost Recovery Clauses" in Item 8 of the Form 10-K for additional information.

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" of Gulf Power in Item 7 and Notes 1 and 3 to the financial statements of Gulf Power under "Revenues" and "Retail Regulatory Matters – Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information.

Over recovered fuel costs at March 31, 2012 totaled $28.8 million compared to $9.9 million at December 31, 2011. These amounts are included in other regulatory liabilities, current on Gulf Power's Condensed Balance Sheets herein.

Purchased Power Capacity Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Purchased Power Capacity Recovery" of Gulf Power in Item 7 and Notes 1 and 3 to the financial statements of Gulf Power under "Revenues" and "Retail Regulatory Matters – Purchased Power Capacity Recovery," respectively, in Item 8 of the Form 10-K for additional information.

Over recovered purchased power capacity costs at March 31, 2012 totaled $9.6 million compared to $8.0 million at December 31, 2011. These amounts are included in other regulatory liabilities, current on Gulf Power's Condensed Balance Sheets herein.

Environmental Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Environmental Cost Recovery" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Environmental Cost Recovery" in Item 8 of the Form 10-K for additional information.

Over recovered environmental costs at March 31, 2012 totaled $4.0 million compared to $10.0 million at December 31, 2011. These amounts are included in other regulatory liabilities, current on Gulf Power's Condensed Balance Sheets herein.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, excluding AFUDC, and it is scheduled for completion in December 2015.

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Energy Conservation Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Energy Conservation Cost Recovery" of Gulf Power in Item 7 and Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Energy Conservation Cost Recovery" in Item 8 of the Form 10-K for additional information.

Under recovered energy conservation costs at March 31, 2012 totaled $2.0 million compared to $3.1 million at December 31, 2011. These amounts are included in under recovered regulatory clause revenues on Gulf Power's Condensed Balance Sheets herein.

Income Tax Matters

Bonus Depreciation

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Gulf Power through 2013. Consequently, Gulf Power's positive cash flow benefit is estimated to be between $105 million and $135 million in 2012.

Other Matters

Gulf Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Gulf Power is subject to certain claims and legal actions arising in the ordinary course of business. Gulf Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against Gulf Power cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Gulf Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Gulf Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Gulf Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Gulf Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Gulf Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – ACCOUNTING POLICIES –

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"Application of Critical Accounting Policies and Estimates" of Gulf Power in Item 7 of the Form 10-K for a complete discussion of Gulf Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Overview" of Gulf Power in Item 7 of the Form 10-K for additional information. Gulf Power's financial condition remained stable at March 31, 2012. Gulf Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $117.5 million for the first three months of 2012 compared to $87.2 million for the corresponding period in 2011. The $30.3 million increase was primarily due to a $26.3 million increase in deferred income taxes related to bonus depreciation and a $16.5 million increase related to reduced purchases of fossil fuel, partially offset by a $16.0 million decrease related to lower retail operating revenues. Net cash used for investing activities totaled $98.8 million in the first three months of 2012 compared to $98.5 million for the corresponding period in 2011. The $0.3 million increase was primarily due to a decrease in gross property additions. Net cash used for financing activities totaled $16.9 million for the first three months of 2012 compared to $15.1 million provided from financing activities for the corresponding period in 2011. The $32.0 million change was primarily due to a $20.7 million decrease in notes payable and a $10 million decrease in issuances of common stock.

Significant balance sheet changes for the first quarter 2012 include a net increase of $82.4 million in property, plant, and equipment, primarily due to the addition of environmental control projects, a $56.7 million increase in accumulated deferred income taxes, primarily related to bonus depreciation, and the issuance of common stock to Southern Company for $40 million.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Gulf Power in Item 7 of the Form 10-K for a description of Gulf Power's capital requirements for its construction program, maturities of long-term debt, as well as the related interest, leases, derivative obligations, preference stock dividends, purchase commitments, and trust funding requirements. There are no requirements through March 31, 2013 to fund maturities of long-term debt.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet new regulatory requirements; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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Sources of Capital

Gulf Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" of Gulf Power in Item 7 of the Form 10-K for additional information.

Gulf Power's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At March 31, 2012, Gulf Power had approximately $19.1 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2012 were as follows:

Expires					Executable Term Loans		Due Within One Year [a]	
2012	2013	2014 and Beyond	Total	Unused	One Year	Two Year	Term Out	No Term Out
(in millions)			(in millions)		(in millions)		(in millions)	
$75	$35	$165	$275	$275	$75	$—	$75	$35

(a) Reflects facilities expiring on or before March 31, 2013.

See Note 6 to the financial statements of Gulf Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

During the first quarter 2012, Gulf Power entered into a new $35 million 364-day committed credit arrangement.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of Gulf Power. Gulf Power is currently in compliance with all such covenants. Gulf Power expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to Gulf Power's commercial paper borrowings and variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2012 was approximately $69 million.

Gulf Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Gulf Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Gulf Power are loaned directly to Gulf Power. The obligations of each traditional operating company under these arrangements are several and there is no cross affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
March 31, 2012:					
Commercial paper	$84	0.2%	$85	0.2%	$117

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, and cash.

Credit Rating Risk

Gulf Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at March 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$126
Below BBB- and/or Baa3	539

Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Gulf Power's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Gulf Power's market risk exposure relative to interest rate changes for the first quarter 2012 has not changed materially compared with the December 31, 2011 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Gulf Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Gulf Power continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. Gulf Power continues to manage a financial hedging program for fuel purchased to operate its electric generating fleet implemented per the

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guidelines of the Florida PSC. As such, Gulf Power had no material change in market risk exposure for the first quarter 2012 when compared with the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2012 were as follows:

	First Quarter 2012 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(41)
Contracts realized or settled	6
Current period changes [(a)]	(19)
Contracts outstanding at the end of the period, assets (liabilities), net	$(54)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the three months ended March 31, 2012 was a decrease of $13 million, of which $12 million related to natural gas swaps and $1 million related to natural gas options. The change is attributable to both the volume of mmBtu and the price of natural gas. At March 31, 2012, Gulf Power had a net hedge volume of 43 million mmBtu, which consisted of 41 million mmBtu of swaps and 2 million mmBtu of options. The weighted average swap contract cost was approximately $1.27 per mmBtu above market prices. At December 31, 2011, Gulf Power had a net hedge volume of 38 million mmBtu, which consisted of 35 million mmBtu of swaps and 3 million mmBtu of options. The weighted average swap contract cost was approximately $1.14 per mmBtu above market prices. The change in option premiums is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through Gulf Power's fuel cost recovery clause.

Regulatory hedges relate to Gulf Power's fuel-hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through Gulf Power's fuel cost recovery clause.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2012 and 2011 for energy-related derivative contracts that are not hedges were not material.

Gulf Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2012 were as follows:

	March 31, 2012 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$—	$—	$—	$—
Level 2	(54)	(33)	(20)	(1)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(54)	$(33)	$(20)	$(1)

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The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by Gulf Power. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until all relevant regulations are finalized.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Gulf Power in Item 7 and Note 1 under "Financial Instruments" and Note 10 to the financial statements of Gulf Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

In January 2012, Gulf Power issued to Southern Company 400,000 shares of Gulf Power's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of Gulf Power's short-term debt and for other general corporate purposes, including Gulf Power's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm-recovery, Gulf Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in thousands)	
Operating Revenues:		
Retail revenues	**$ 166,271**	$ 180,474
Wholesale revenues, non-affiliates	**54,231**	69,851
Wholesale revenues, affiliates	**4,040**	9,300
Other revenues	**4,172**	3,651
Total operating revenues	**228,714**	263,276
Operating Expenses:		
Fuel	**88,619**	121,054
Purchased power, non-affiliates	**1,943**	1,010
Purchased power, affiliates	**8,860**	8,350
Other operations and maintenance	**54,895**	70,367
Depreciation and amortization	**22,481**	19,863
Taxes other than income taxes	**21,703**	17,481
Total operating expenses	**198,501**	238,125
Operating Income	**30,213**	25,151
Other Income and (Expense):		
Allowance for equity funds used during construction	**11,827**	3,131
Interest income	**120**	342
Interest expense, net of amounts capitalized	**(7,805)**	(6,013)
Other income (expense), net	**(242)**	(403)
Total other income and (expense)	**3,900**	(2,943)
Earnings Before Income Taxes	**34,113**	22,208
Income taxes	**8,425**	7,158
Net Income	**25,688**	15,050
Dividends on Preferred Stock	**433**	433
Net Income After Dividends on Preferred Stock	**$ 25,255**	$ 14,617

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in thousands)	
Net Income After Dividends on Preferred Stock	**$ 25,255**	$ 14,617
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $(296) and $(1), respectively	**(478)**	(2)
Reclassification adjustment for amounts included in net income, net of tax of $16 and $-, respectively	**26**	—
Total other comprehensive income (loss)	**(452)**	(2)
Comprehensive Income	**$ 24,803**	$ 14,615

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

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MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Operating Activities:		
Net income	**$ 25,688**	$ 15,050
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**21,931**	21,442
Deferred income taxes	**(1,210)**	10,015
Investment tax credits received	**13,974**	9,750
Allowance for equity funds used during construction	**(11,827)**	(3,131)
Pension, postretirement, and other employee benefits	**2,268**	1,037
Hedge settlements	**(15,983)**	—
Stock based compensation expense	**957**	813
Other, net	**(1,127)**	(1,363)
Changes in certain current assets and liabilities —		
-Receivables	**14,536**	11,592
-Fossil fuel stock	**(16,188)**	(538)
-Materials and supplies	**(538)**	(317)
-Prepaid income taxes	**4,168**	15,976
-Other current assets	**(4,357)**	1,649
-Accounts payable	**(11,558)**	17,538
-Accrued taxes	**(31,434)**	(31,213)
-Accrued compensation	**(10,803)**	(9,556)
-Over recovered regulatory clause revenues	**12,627**	7,756
-Other current liabilities	**9,480**	(149)
Net cash provided from operating activities	**604**	66,351
Investing Activities:		
Property additions	**(370,923)**	(148,917)
Cost of removal, net of salvage	**(1,149)**	(2,830)
Construction payables	**30,080**	33,291
Capital grant proceeds	**1,816**	16,912
Distribution of restricted cash	**—**	50,000
Other investing activities	**(4,207)**	(834)
Net cash used for investing activities	**(344,383)**	(52,378)
Financing Activities:		
Proceeds —		
Capital contributions from parent company	**150,735**	50,610
Senior notes issuances	**400,000**	—
Interest-bearing refundable deposit related to asset sale	**150,000**	—
Redemptions —		
Capital leases	**(377)**	(349)
Other long-term debt	**(75,000)**	(130,000)
Payment of preferred stock dividends	**(433)**	(433)
Payment of common stock dividends	**(26,700)**	(18,875)
Other financing activities	**715**	(312)
Net cash provided from (used for) financing activities	**598,940**	(99,359)
Net Change in Cash and Cash Equivalents	**255,161**	(85,386)
Cash and Cash Equivalents at Beginning of Period	**211,585**	160,779
Cash and Cash Equivalents at End of Period	**$ 466,746**	$ 75,393
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (paid $5,965 and $7,129, net of $6,565 and $994 capitalized for 2012 and 2011, respectively)	**$ —**	$ 6,135
Income taxes (net of refunds)	**(11,994)**	(32,294)
Noncash transactions — accrued property additions at end of period	**165,982**	72,114

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

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MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2012	At December 31, 2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 466,746**	$ 211,585
Receivables —		
Customer accounts receivable	**27,836**	32,551
Unbilled revenues	**27,231**	27,239
Other accounts and notes receivable	**3,716**	7,080
Affiliated companies	**19,463**	23,078
Accumulated provision for uncollectible accounts	**(415)**	(547)
Fossil fuel stock, at average cost	**156,360**	140,173
Materials and supplies, at average cost	**31,325**	30,787
Other regulatory assets, current	**75,249**	69,201
Prepaid income taxes	**37,408**	37,793
Other current assets	**10,000**	8,881
Total current assets	**854,919**	587,821
Property, Plant, and Equipment:		
In service	**2,912,571**	2,902,240
Less accumulated provision for depreciation	**1,035,946**	1,019,251
Plant in service, net of depreciation	**1,876,625**	1,882,989
Construction work in progress	**1,323,400**	955,135
Total property, plant, and equipment	**3,200,025**	2,838,124
Other Property and Investments	**6,288**	6,520
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**39,703**	25,009
Other regulatory assets, deferred	**190,894**	185,694
Other deferred charges and assets	**30,422**	28,674
Total deferred charges and other assets	**261,019**	239,377
Total Assets	**$ 4,322,251**	$ 3,671,842

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder’s Equity	At March 31, 2012	At December 31, 2011
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 255,255	$ 240,633
Interest-bearing refundable deposit related to asset sale	150,000	—
Accounts payable —		
Affiliated	50,786	62,650
Other	198,396	168,309
Customer deposits	13,993	13,658
Accrued taxes —		
Accrued income taxes	5,922	3,813
Other accrued taxes	20,364	53,825
Accrued interest	22,264	12,750
Accrued compensation	5,086	15,889
Other regulatory liabilities, current	5,535	5,779
Over recovered regulatory clause liabilities	73,129	60,502
Liabilities from risk management activities	39,649	54,127
Other current liabilities	20,797	17,533
Total current liabilities	861,176	709,468
Long-term Debt	1,412,662	1,103,596
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	259,903	270,397
Deferred credits related to income taxes	10,800	11,058
Accumulated deferred investment tax credits	150,983	109,761
Employee benefit obligations	162,007	161,065
Other cost of removal obligations	130,909	126,424
Other regulatory liabilities, deferred	61,831	60,848
Other deferred credits and liabilities	39,700	37,228
Total deferred credits and other liabilities	816,133	776,781
Total Liabilities	3,089,971	2,589,845
Redeemable Preferred Stock	32,780	32,780
Common Stockholder’s Equity:		
Common stock, without par value —		
Authorized - 1,130,000 shares		
Outstanding - 1,121,000 shares	37,691	37,691
Paid-in capital	847,035	694,855
Retained earnings	324,123	325,568
Accumulated other comprehensive loss	(9,349)	(8,897)
Total common stockholder’s equity	1,199,500	1,049,217
Total Liabilities and Stockholder’s Equity	$ 4,322,251	$ 3,671,842

The accompanying notes as they relate to Mississippi Power are an integral part of these condensed financial statements.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRST QUARTER 2012 vs. FIRST QUARTER 2011

OVERVIEW

Mississippi Power operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast. Many factors affect the opportunities, challenges, and risks of Mississippi Power's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel prices, capital expenditures, and restoration following major storms. In addition, Mississippi Power is currently constructing the Kemper IGCC. Mississippi Power has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge Mississippi Power for the foreseeable future.

Mississippi Power continues to focus on several key performance indicators. In recognition that Mississippi Power's long-term financial success is dependent upon how well it satisfies its customers' needs, Mississippi Power's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to Mississippi Power's allowed return. In addition to the PEP performance indicators, Mississippi Power focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS — OVERVIEW — "Key Performance Indicators" of Mississippi Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$10.7	72.8

Mississippi Power's net income after dividends on preferred stock for the first quarter 2012 was $25.3 million compared to $14.6 million for the corresponding period in 2011. The increase in net income after dividends on preferred stock for the first quarter 2012 was the result of an increase in AFUDC equity primarily related to the construction of the Kemper IGCC, which began in June 2010, and a decrease in operations and maintenance expenses. These factors were partially offset by a decrease in territorial base revenues resulting from milder weather in the first quarter 2012 compared to the corresponding period in 2011. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Integrated Coal Gasification Combined Cycle" and Note (B) to the Condensed Financial Statements herein for additional information regarding the Kemper IGCC.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Retail Revenues

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(14.2)	(7.9)

In the first quarter 2012, retail revenues were $166.3 million compared to $180.5 million for the corresponding period in 2011.

Details of the change to retail revenues were as follows:

	First Quarter 2012	
	(in millions)	*(% change)*
Retail – prior year	$180.5	
Estimated change in –		
Rates and pricing	(1.1)	(0.6)
Sales growth (decline)	3.1	1.7
Weather	(4.9)	(2.7)
Fuel and other cost recovery	(11.3)	(6.3)
Retail – current year	$166.3	(7.9)%

Revenues associated with changes in rates and pricing decreased in the first quarter 2012 when compared to the corresponding period in 2011 due to a decrease of $1.1 million related to the ECO Plan rate.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Environmental Compliance Overview Plan" of Mississippi Power in Item 7 of the Form 10-K and FUTURE EARNINGS POTENTIAL – "PSC Matters – Environmental Compliance Overview Plan" herein for additional information.

Revenues attributable to changes in sales increased in the first quarter 2012 when compared to the corresponding period in 2011. KWH energy sales to industrial customers increased 4.7% due to increased production for several large industrial customers resulting from continued economic recovery. Weather-adjusted KWH energy sales to residential and commercial customers increased 1.2% and 0.9%, respectively, when compared to the corresponding period in 2011 due to a small increase in the number of customers.

Revenues attributable to changes in weather decreased in the first quarter 2012 when compared to the corresponding period for 2011 primarily due to milder weather in the first quarter 2012.

Fuel and other cost recovery revenues decreased in the first quarter 2012 when compared to the corresponding period in 2011 primarily as a result of lower recoverable fuel costs. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside Mississippi Power's service territory. Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power costs, and do not affect net income.

Wholesale Revenues – Non-Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(15.7)	(22.4)

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Mississippi Power's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

In the first quarter 2012, wholesale revenues from non-affiliates were $54.2 million compared to $69.9 million for the corresponding period in 2011. The decrease was due to a $10.9 million decrease in energy revenues, of which $5.0 million was associated with a decrease in KWH sales due to lower demand primarily resulting from milder weather in the first quarter 2012 compared to the corresponding period in 2011 and $5.9 million was associated with lower fuel prices, and a $4.8 million decrease in capacity revenues resulting from lower customer demand.

Wholesale Revenues – Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(5.3)	(56.6)

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the IIC, as approved by the FERC. These transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost.

In the first quarter 2012, wholesale revenues from affiliates were $4.0 million compared to $9.3 million for the corresponding period in 2011. The decrease was primarily due to a $5.2 million decrease in energy revenues, of which $2.8 million was associated with a decrease in KWH sales and $2.4 million was associated with lower prices.

Fuel and Purchased Power Expenses

	First Quarter 2012 vs. First Quarter 2011	
	(change in millions)	*(% change)*
Fuel	($32.5)	(26.8)
Purchased power — non-affiliates	0.9	92.4
Purchased power — affiliates	0.6	6.1
Total fuel and purchased power expenses	($31.0)	

In the first quarter 2012, total fuel and purchased power expenses were $99.4 million compared to $130.4 million for the corresponding period in 2011. The decrease was primarily due to an $18.0 million decrease in the cost of fuel and purchased power and a $13.0 million decrease in total KWHs generated and purchased as a result of lower KWH demand primarily due to milder weather in the first quarter 2012.

Fuel and purchased power energy transactions do not have a significant impact on earnings since energy expenses are generally offset by energy revenues through Mississippi Power's fuel cost recovery clause. See FUTURE EARNINGS POTENTIAL — "PSC Matters" herein for additional information.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Details of Mississippi Power's generation and purchased power were as follows:

	First Quarter 2012	First Quarter 2011
Total generation *(millions of KWHs)*	**2,982**	3,364
Total purchased power *(millions of KWHs)*	**447**	304
Sources of generation *(percent)* –		
Coal	**21**	35
Gas	**79**	65
Cost of fuel, generated *(cents per net KWH)* –		
Coal	**4.77**	4.23
Gas	**2.83**	3.72
Average cost of fuel, generated *(cents per net KWH)*	**3.29**	3.92
Average cost of purchased power *(cents per net KWH)*	**2.42**	3.08

Fuel

In the first quarter 2012, fuel expense was $88.6 million compared to $121.1 million for the corresponding period in 2011. The decrease was primarily due to a 23.9% decrease in the average cost of natural gas per KWH generated primarily resulting from lower gas prices and a 12.7% decrease in generation from Mississippi Power's facilities resulting from lower energy demand primarily due to milder weather in the first quarter 2012 compared to the corresponding period in 2011.

Purchased Power – Non-Affiliates

In the first quarter 2012, purchased power expense from non-affiliates was $1.9 million compared to $1.0 million for the corresponding period in 2011. The increase was primarily the result of a 77.6% increase in KWH volume purchased and an 8.3% increase in the average cost of purchased power per KWH. The increase in the volume of KWHs purchased was due to a decrease in generation from Mississippi Power's facilities. The increase in the average cost per KWH purchased was due to a higher marginal cost of fuel.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

In the first quarter 2012, purchased power expense from affiliates was $8.9 million compared to $8.3 million for the corresponding period in 2011. The increase was primarily due to a 40.3% increase in KWH volume purchased, partially offset by a 24.4% decrease in the average cost of purchased power per KWH.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC, as approved by the FERC.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Other Operations and Maintenance Expenses

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(15.5)	(22.0)

In the first quarter 2012, other operations and maintenance expenses were $54.9 million compared to $70.4 million for the corresponding period in 2011. The decrease was primarily due to a $10.8 million decrease in rent expense and expenses under a long-term service agreement resulting from the expiration of an operating lease for Plant Daniel Units 3 and 4 in October 2011 and a $6.5 million decrease in generation expenses primarily related to scheduled outages. These decreases were partially offset by a $1.3 million increase in administrative and general expenses. See Note 1 to the financial statements of Mississippi Power under "Purchase of the Plant Daniel Combined Cycle Generating Units" in Item 8 of the Form 10-K for additional information.

Depreciation and Amortization

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$2.6	13.2

In the first quarter 2012, depreciation and amortization was $22.5 million compared to $19.9 million for the corresponding period in 2011. The increase was primarily due to a $3.3 million increase in depreciation on additional plant in service and a $1.9 million increase in amortization resulting from the plant acquisition adjustment related to the purchase of Plant Daniel Units 3 and 4. These increases were partially offset by a $2.6 million decrease in amortization primarily resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4.

See Note 1 to the financial statements of Mississippi Power under "Purchase of the Plant Daniel Combined Cycle Generating Units" and "Depreciation and Amortization" in Item 8 of the Form 10-K for additional information.

Taxes Other Than Income Taxes

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$4.2	24.2

In the first quarter 2012, taxes other than income taxes were $21.7 million compared to $17.5 million for the corresponding period in 2011. The increase was primarily due to a $4.0 million increase in ad valorem taxes and a $0.2 million increase in franchise taxes.

The retail portion of ad valorem taxes is recoverable under Mississippi Power's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Allowance for Equity Funds Used During Construction

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$8.7	N/M

N/M — Not meaningful

In the first quarter 2012, AFUDC equity was $11.8 million compared to $3.1 million for the corresponding period in 2011. The increase was primarily due to the construction of the Kemper IGCC.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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See Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL — "Integrated Coal Gasification Combined Cycle" herein for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$1.8	29.8

In the first quarter 2012, interest expense, net of amounts capitalized was $7.8 million compared to $6.0 million for the corresponding period in 2011. The increase was primarily due to an $8.6 million increase in interest expense associated with the issuances of new long-term debt in April 2011, September 2011, October 2011, and March 2012 and a $1.1 million increase in interest expense resulting from the receipt of a $150 million interest-bearing refundable deposit from SMEPA in March 2012 related to its pending purchase of a 17.5% undivided interest in the Kemper IGCC. The increase was partially offset by a $5.6 million increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC and a $1.9 million decrease in interest expense resulting from the amortization of the fair value adjustment on the assumed debt related to the purchase of Plant Daniel Units 3 and 4 in October 2011.

See Note 1 to the financial statements of Mississippi Power under "Purchase of the Plant Daniel Combined Cycle Generating Units" in Item 8 of the Form 10-K and FUTURE EARNINGS POTENTIAL — "Integrated Coal Gasification Combined Cycle" herein for additional information.

Income Taxes

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$1.2	17.7

In the first quarter 2012, income taxes were $8.4 million compared to $7.2 million for the corresponding period in 2011. The increase was primarily due to a $4.7 million increase resulting from higher pre-tax earnings and a $0.3 million increase due to lower State of Mississippi manufacturing investment tax credits, partially offset by a $3.4 million decrease due to higher AFUDC equity, which is non-taxable, and a $0.3 million decrease in unrecognized tax benefits.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Mississippi Power's future earnings potential. The level of Mississippi Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Mississippi Power's business of selling electricity. These factors include Mississippi Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in Mississippi Power's service territory. Changes in economic conditions impact sales for Mississippi Power and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL of Mississippi Power in Item 7 of the Form 10-K.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Environmental Matters" in Item 8 of the Form 10-K for additional information.

New Source Review Actions

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — New Source Review Actions" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Environmental Matters — New Source Review Actions" in Item 8 of the Form 10-K for additional information. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power (including claims related to a unit co-owned by Mississippi Power). At the same time, the EPA asked the U.S. Court of Appeals for the Eleventh Circuit to stay its appeal of the judgment in favor of Alabama Power. Alabama Power filed oppositions to the EPA's motion and its request for a stay. On March 29, 2012, the U.S. Court of Appeals for the Eleventh Circuit denied the EPA's request to stay its appeal. The U.S. District Court for the Northern District of Alabama has not ruled on the EPA's motion seeking vacatur of the judgment. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Environmental Statutes and Regulations — General" of Mississippi Power in Item 7 of the Form 10-K for information regarding Mississippi Power's estimated base level capital expenditures to comply with existing statutes and regulations for 2012 through 2014, as well as Mississippi Power's preliminary estimates for potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) and the EPA's proposed water and coal combustion byproducts rules. Mississippi Power is continuing to develop its compliance strategy and to assess the potential costs of complying with the MATS rule and the EPA's proposed water and coal combustion byproducts rules.

Mississippi Power's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations that are promulgated, including any proposed environmental regulations; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and Mississippi Power's fuel mix. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. Mississippi Power's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

Air Quality

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Environmental Statutes and Regulations — Air Quality" of Mississippi Power in Item 7 of the Form 10-K for additional information on the eight-hour ozone air quality standards and the MATS rule.

On May 1, 2012, the EPA released its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. None of the areas within Mississippi Power's service territory were designated as nonattainment areas.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by Southern Company and its subsidiaries, including Mississippi Power, have been filed with the EPA. Challenges to the final rule have also been filed in the U.S. District Court of Appeals for the District of Columbia by numerous states, environmental organizations, industry groups, and others. The impact of the MATS rule will depend on the outcome of these and any other legal challenges and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Environmental Statutes and Regulations — Coal Combustion Byproducts" of Mississippi Power in Item 7 of the Form 10-K for additional information. On April 5, 2012, 10 environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts as soon as possible. Other parties are expected to file similar challenges. The ultimate outcome of this matter cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Global Climate Issues" of Mississippi Power in Item 7 of the Form 10-K for additional information. On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. As proposed, the standards would not apply to existing units. The EPA has delayed its plans to propose greenhouse gas emissions performance standards for modified sources and emissions guidelines for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "FERC Matters" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "FERC Matters" in Item 8 of the Form 10-K for additional information.

On January 20, 2012, Mississippi Power reached a settlement agreement with its wholesale customers, which was executed by all parties on March 9, 2012. The settlement agreement provides that base rates under the cost-based electric tariff will increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. In 2012, the amount of base rate revenues to be received from the agreed upon increase will be approximately $17.0 million. On March 12, 2012, Mississippi Power filed an unopposed motion to place wholesale Municipal and Rural Associations (MRA) interim rates into effect pending approval of the settlement agreement between the parties by the FERC. On March 28, 2012, the FERC approved the motion to place interim rates into effect beginning in May 2012. Approval of the settlement agreement by the FERC has been delayed until later in the year.

The ultimate outcome of this matter cannot be determined at this time.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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PSC Matters

Performance Evaluation Plan

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "PSC Matters — Performance Evaluation Plan" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters — Performance Evaluation Plan" in Item 8 of the Form 10-K for additional information regarding Mississippi Power's base rates.

On April 2, 2012, Mississippi Power filed a motion to suspend the 2011 PEP lookback filing. Unresolved matters related to certain costs included in the 2010 PEP lookback filing also impact the 2011 PEP lookback filing, making it impractical to determine Mississippi Power's actual retail return on investment for 2011 for purposes of the 2011 PEP lookback filing. The ultimate outcome of these matters cannot be determined at this time.

Environmental Compliance Overview Plan

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "PSC Matters — Environmental Compliance Overview Plan" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters — Environmental Compliance Overview Plan" in Item 8 of the Form 10-K for information on Mississippi Power's annual environmental filing with the Mississippi PSC.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with Mississippi Power's portion being $330 million, excluding AFUDC. The project is scheduled for completion in December 2015. Mississippi Power's portion of the cost is expected to be recovered through the ECO Plan. As of March 31, 2012, total project expenditures were $55.6 million, with Mississippi Power's portion being $27.8 million.

On February 14, 2012, Mississippi Power submitted its 2012 ECO Plan notice, which proposed a 0.3% increase in annual revenues for Mississippi Power. In compliance with the CPCN to construct scrubbers on Plant Daniel Units 1 and 2, Mississippi Power will revise the 2012 ECO Plan notice excluding scrubber expenditures from rate base, which is expected to result in little or no rate change.

The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "PSC Matters — Fuel Cost Recovery" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters — Fuel Cost Recovery" in Item 8 of the Form 10-K for information regarding Mississippi Power's fuel cost recovery.

At March 31, 2012, the amount of over recovered retail fuel costs included in Mississippi Power's Condensed Balance Sheets herein was $50.9 million compared to $42.4 million at December 31, 2011. Mississippi Power also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. At March 31, 2012, the amount of over recovered wholesale MRA and MB fuel costs included in Mississippi Power's Condensed Balance Sheets was $18.1 million and $2.4 million, respectively, compared to $14.3 million and $2.2 million, respectively, at December 31, 2011. In addition, at March 31, 2012 and December 31, 2011, the amount of over recovered MRA emissions allowance cost included in Mississippi Power's Condensed Balance Sheets herein was $1.7 million. Mississippi Power's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this decrease to the billing factors will have no significant effect on Mississippi Power's revenues or net income, but will decrease annual cash flow.

Integrated Coal Gasification Combined Cycle

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Integrated Coal Gasification Combined Cycle" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K for information regarding Mississippi Power's construction of the Kemper IGCC.

In May 2010, Mississippi Power filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming Mississippi Power's application for a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN (2010 MPSC Order).

In June 2010, the Sierra Club filed an appeal of the Mississippi PSC's June 2010 decision to grant the CPCN for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, in July 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. In October 2010, the Mississippi Supreme Court dismissed the Sierra Club's direct appeal. On February 28, 2011, the Chancery Court issued a judgment affirming the 2010 MPSC Order and, on March 1, 2011, the Sierra Club appealed the Chancery Court's decision to the Mississippi Supreme Court. On March 15, 2012, the Mississippi Supreme Court reversed the Chancery Court's decision and the 2010 MPSC Order and remanded the matter to the Mississippi PSC to correct the 2010 MPSC Order. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN.

On March 30, 2012, the Mississippi PSC issued temporary authorization for the continuation of construction of the Kemper IGCC until the earlier of the conclusion of the Mississippi PSC's May 2012 open meeting or immediately upon the issuance of any final order issued by the Mississippi PSC on remand that conclusively addresses the mandate. On April 24, 2012, the Mississippi PSC issued a detailed order on remand (2012 MPSC Order) confirming the CPCN for the Kemper IGCC subject to the same conditions set forth in the 2010 MPSC Order. On April 26, 2012, the Sierra Club filed a motion for stay and a notice of appeal of the 2012 MPSC Order with the Chancery Court. On May 2, 2012, Mississippi Power filed a petition to join the appeal.

The certificated cost estimate of the Kemper IGCC is $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities. The 2012 MPSC Order, like the 2010 MPSC Order, (1) approved a construction cost cap of up to $2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the CO_2 pipeline facilities), (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's proposal, and (3) approved financing cost recovery on CWIP balances not to exceed the certificated cost estimate, which provided for the accrual of AFUDC in 2010 and 2011 and provides for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014, (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by Mississippi Power in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). As of March 31, 2012, Mississippi Power had utilized substantially all of its contingency contained in the certificated cost estimate. Mississippi Power anticipates that the costs to complete construction of the portion of the Kemper IGCC subject to the construction cost cap will be less than the cost cap but will likely exceed the certificated cost estimate.

The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. Of the total costs incurred through March 2009, $46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining $5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs has not been determined.

The Kemper IGCC plant, expected to begin commercial operation in May 2014, will use locally mined lignite (an abundant, lower heating value coal) from a mine adjacent to the plant as fuel. The mine is scheduled to be placed into service in June 2013. In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $245 million, of which $79.7 million has been incurred through March 31, 2012. The asset retirement obligation associated with the reclamation and restoration of the mine currently under construction was immaterial at March 31, 2012. In May 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. The contract with Liberty Fuels is effective June 2010 through the end of the mine reclamation. On December 13, 2011, the Mississippi Department of Environmental Quality (MDEQ) approved the surface coal mining and the water pollution control permits for the mining operations operated by Liberty Fuels. On January 12, 2012, two individuals each filed a notice of appeal and a request for evidentiary hearing with the MDEQ regarding the surface coal mining and water pollution control permits. On March 8, 2012, the MDEQ permit board affirmed its issuance of the surface coal mining and water pollution control permits.

In 2009, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $133 million of Internal Revenue Code Section 48A tax credits (Phase I) to Mississippi Power. On April 19, 2011, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to Mississippi Power. The utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the recapture rules for Section 48A investment tax credits. Through March 31, 2012, Mississippi Power received or accrued tax benefits totaling $141.1 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, Mississippi Power estimates that it will not be able to utilize $105.0 million of these tax credits until after 2012. IRS guidelines allow the resulting unused credits to be carried forward for 20 years.

In July 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In December 2010, Mississippi Power and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval of SMEPA's 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the joint petition for the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power's senior unsecured credit rating falls below a BBB+ and/or Baa1. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the deposit has been presented as a current liability in Mississippi Power's Condensed Balance Sheet herein and as financing proceeds in the statement of cash flows.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

As of March 31, 2012, Mississippi Power had spent a total of $1.30 billion on the Kemper IGCC including the cost of the lignite mine and equipment, the CO_2 pipeline facilities, and regulatory filing costs. Of this total, $1.28 billion was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $22.9 million was recorded in other regulatory assets, $2.3 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "PSC Matters — Certificated New Plant" of Mississippi Power in Item 7 and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters — Certificated New Plant" in Item 8 of the Form 10-K for information on the proposed rate schedules related to the Kemper IGCC.

The ultimate outcome of these matters cannot be determined at this time.

Income Tax Matters

Bonus Depreciation

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). Due to the significant amount of estimated bonus depreciation for 2012 for Southern Company, a portion of Mississippi Power's tax credit utilization will be deferred, thus eliminating the positive cash flow benefit for Mississippi Power.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Integrated Coal Gasification Combined Cycle" herein for additional information.

Other Matters

Mississippi Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Mississippi Power is subject to certain claims and legal actions arising in the ordinary course of business. Mississippi Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against Mississippi Power cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Mississippi Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Mississippi Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Mississippi Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Mississippi Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Mississippi Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS — ACCOUNTING POLICIES — "Application of Critical Accounting Policies and Estimates" of Mississippi Power in Item 7 of the Form 10-K for a complete discussion of Mississippi Power's critical accounting policies and estimates related to Electric Utility Regulation, Contingent Obligations, Unbilled Revenues, and Pension and Other Postretirement Benefits.

FINANCIAL CONDITION AND LIQUIDITY

Overview

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Overview" of Mississippi Power in Item 7 of the Form 10-K for additional information. Mississippi Power's financial condition remained stable at March 31, 2012. Mississippi Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $0.6 million for the first three months of 2012 compared to $66.4 million for the corresponding period in 2011. The $65.8 million decrease in cash provided from operating activities is primarily due to a $16.0 million decrease in hedge settlements related to the settlement of interest rate swaps, a $15.7 million increase in fuel inventory, and a decrease in accounts payable of $29.1 million primarily due to timing of cash payments.

Net cash used for investing activities totaled $344.4 million for the first three months of 2012 compared to $52.4 million for the corresponding period in 2011. The $292.0 million increase in net cash used for investing activities is primarily due to an increase in property additions of $222.0 million primarily related to the Kemper IGCC, a $50.0 million decrease in restricted cash, and a $15.1 million decrease in capital grant proceeds related to CCPI2 and smart grid investment grants.

Net cash provided from financing activities totaled $598.9 million for the first three months of 2012 compared to net cash used for financing activities of $99.4 million for the corresponding period in 2011. The $698.3 million increase in net cash provided from financing activities was primarily due to a $100.1 million increase in capital contributions from Southern Company, the issuance of $400.0 million of senior notes in March 2012, the receipt of a $150.0 million interest-bearing refundable deposit related to a pending asset sale, and a $55.0 million decrease in redemptions of long-term debt in the first quarter 2012 compared to the corresponding period in 2011.

Significant balance sheet changes for the first three months of 2012 include an increase in cash and cash equivalents of $255.2 million primarily due to the issuance of $400.0 million of senior notes and the receipt of a $150.0 million interest-bearing refundable deposit from SMEPA to be applied towards its pending purchase of a 17.5% undivided interest in the Kemper IGCC. Total property, plant, and equipment increased $361.9 million primarily due to the increase in CWIP related to the Kemper IGCC. Interest-bearing refundable deposit related to an asset sale increased $150.0 million due to the receipt of the $150.0 million interest-bearing refundable deposit from SMEPA. Long-term debt increased $309.1 million primarily due to the issuance of $400.0 million of senior notes. Paid-in capital increased $152.2 million due to a $150.0 million capital contribution from Southern Company.

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Capital Requirements and Contractual Obligations" of Mississippi Power in Item 7 of the Form 10-K for a description of Mississippi Power's capital requirements for its construction program, lease obligations, purchase commitments, derivative obligations, preferred stock dividends, and trust funding requirements. Approximately $255 million will be required through March 31, 2013 to fund maturities and announced redemptions of long-term debt.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet new regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Sources of Capital

Except as described below with respect to potential DOE loan guarantees, Mississippi Power plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily funds from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. On February 27, 2012, Mississippi Power received a $150 million capital contribution from Southern Company. On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA towards its pending purchase of a 17.5% undivided interest in the Kemper IGCC. Until the acquisition is closed, Mississippi Power has agreed to pay interest on the deposit at its AFUDC rate, which was 10.196% at March 31, 2012. While the expectation is that the amount will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power's senior unsecured credit rating falls below a BBB+ and/or Baa1. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Sources of Capital" of Mississippi Power in Item 7 of the Form 10-K for additional information.

Mississippi Power has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. Mississippi Power is in advanced due diligence with the DOE. There can be no assurance that the DOE will issue federal loan guarantees to Mississippi Power. Mississippi Power has received $245.3 million in DOE CCPI2 grant funds that were used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC. Investment tax credits related to the Kemper IGCC of $105.0 million are not expected to be utilized until after 2012, which could result in additional financing needs.

Mississippi Power's current liabilities sometimes exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

At March 31, 2012, Mississippi Power had approximately $466.7 million of cash and cash equivalents. Committed credit arrangements with banks at March 31, 2012 were as follows:

Expires					**Executable Term Loans**		**Due Within One Year** [(a)]	
2012	**2013**	**2014 and Beyond**	**Total**	**Unused**	**One Year**	**Two Year**	**Term Out**	**No Term Out**
(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
$106	$25	$165	$296	$296	$25	$41	$66	$65

(a) Reflects facilities expiring on or before March 31, 2013.

See Note 6 to the financial statements of Mississippi Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of Mississippi Power. Mississippi Power is currently in compliance with all such covenants. Mississippi Power expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to Mississippi Power's commercial paper borrowings and variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of March 31, 2012 was approximately $40 million.

Mississippi Power may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of Mississippi Power and the other traditional operating companies. Proceeds from such issuances for the benefit of Mississippi Power are loaned directly to Mississippi Power. The obligations of each traditional operating company under these arrangements are several and there is no cross affiliate credit support.

Mississippi Power had no commercial paper or short-term debt outstanding during the three months ended March 31, 2012.

Management believes that the need for working capital can be adequately met by utilizing commercial paper, lines of credit, and cash.

Credit Rating Risk

Mississippi Power does not have any credit arrangements with banks that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management. At March 31, 2012, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $329 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Mississippi Power also has entered into an asset purchase agreement with SMEPA for the pending purchase of a 17.5% undivided interest in the Kemper IGCC that could require a refund of the deposit within 15 days at SMEPA's discretion in the event that Mississippi Power's senior unsecured credit rating falls below a BBB+ and/or Baa1. Additionally, any credit rating downgrade could impact Mississippi Power's ability to access capital markets, particularly the short-term debt market.

MISSISSIPPI POWER COMPANY
MANAGEMENT’S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Market Price Risk

Mississippi Power’s market risk exposure relative to interest rate changes for the first quarter 2012 has not changed materially compared with the December 31, 2011 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, Mississippi Power is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation and other various cost recovery mechanisms, Mississippi Power continues to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, Mississippi Power enters into physical fixed-price contracts or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market. Mississippi Power continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. As such, Mississippi Power had no material change in market risk exposure for the first quarter 2012 when compared with the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the three months ended March 31, 2012 were as follows:

	First Quarter 2012 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(51)
Contracts realized or settled	10
Current period changes [(a)]	(15)
Contracts outstanding at the end of the period, assets (liabilities), net	$(56)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The change in the fair value positions of the energy-related derivative contracts for the three months ended March 31, 2012 was a decrease of $5 million, of which $3 million related to natural gas swaps and $2 million related to natural gas options. The change is attributable to both the volume of mmBtu and the price of natural gas. At March 31, 2012, Mississippi Power had a net hedge volume of 28 million mmBtu, which consisted of 21 million mmBtu of swaps and 7 million mmBtu of options. The weighted average swap contract cost was approximately $2.13 per mmBtu above market prices. At December 31, 2011, Mississippi Power had a net hedge volume of 31 million mmBtu, which consisted of 22 million mmBtu of swaps and 9 million mmBtu of options. The weighted average swap contract cost was approximately $1.98 per mmBtu above market prices. The change in option premiums is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the costs associated with natural gas hedges are recovered through Mississippi Power’s energy cost management clause (ECM).

Regulatory hedges relate to Mississippi Power’s fuel-hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through Mississippi Power’s ECM.

Unrealized pre-tax gains and losses recognized in income for the three months ended March 31, 2012 and 2011 for energy-related derivative contracts that are not hedges were not material.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Mississippi Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2012 were as follows:

	March 31, 2012 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$—
Level 2	(56)	(40)	(15)	(1)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(56)	$(40)	$(15)	$(1)

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by Mississippi Power. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until all relevant regulations are finalized.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of Mississippi Power in Item 7 and Note 1 under "Financial Instruments" and Note 10 to the financial statements of Mississippi Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

In March 2012, Mississippi Power issued $250 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042 and an additional $150 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016. The Series 2011A 2.35% Senior Notes due October 15, 2016 were of the same series of notes that were originally issued in October 2011 in the aggregate principal amount of $150 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2011A 2.35% Senior Notes was $300 million. The proceeds from the sale of the Series 2012A Senior Notes and the Series 2011A Senior Notes were used to repay a bank loan in an aggregate principal amount of $75 million, and for general corporate purposes, including Mississippi Power's continuous construction program.

In March 2012, $300 million in interest rate swaps were settled; $250 million related to its Series 2012A 4.25% Senior Notes at a loss of approximately $13.3 million, which will be amortized to interest expense, in earnings, over 10 years, and $50 million related to its Series 2011A 2.35% Senior Notes at a loss of approximately $2.7 million, which will be amortized to interest expense, in earnings, over 10 years.

On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of a 17.5% undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power's senior unsecured credit rating falls below a BBB+ and/or Baa1.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Subsequent to March 31, 2012, Mississippi Power announced the redemption of $90 million aggregate principal amount of Series E 5-5/8% Senior Notes due May 1, 2033 that will occur on May 15, 2012.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Mississippi Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

SOUTHERN POWER COMPANY
AND SUBSIDIARY COMPANIES

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in thousands)	
Operating Revenues:		
Wholesale revenues, non-affiliates	**$140,557**	$197,166
Wholesale revenues, affiliates	**111,788**	83,274
Other revenues	**1,336**	1,347
Total operating revenues	**253,681**	281,787
Operating Expenses:		
Fuel	**89,078**	102,715
Purchased power, non-affiliates	**20,650**	8,942
Purchased power, affiliates	**2,340**	15,099
Other operations and maintenance	**48,389**	42,754
Depreciation and amortization	**31,913**	30,167
Taxes other than income taxes	**4,968**	4,763
Total operating expenses	**197,338**	204,440
Operating Income	**56,343**	77,347
Other Income and (Expense):		
Interest expense, net of amounts capitalized	**(13,642)**	(18,829)
Other income (expense), net	**30**	59
Total other income and (expense)	**(13,612)**	(18,770)
Earnings Before Income Taxes	**42,731**	58,577
Income taxes	**13,415**	20,834
Net Income	**$ 29,316**	$ 37,743

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2012	2011
	(in thousands)	
Net Income	**$ 29,316**	$ 37,743
Other comprehensive income (loss):		
Qualifying hedges:		
Changes in fair value, net of tax of $(173) and $423, respectively	**(274)**	643
Reclassification adjustment for amounts included in net income, net of tax of $956 and $1,071, respectively	**1,510**	1,630
Total other comprehensive income (loss)	**1,236**	2,273
Comprehensive Income	**$ 30,552**	$ 40,016

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Operating Activities:		
Net income	**$ 29,316**	$ 37,743
Adjustments to reconcile net income to net cash provided from operating activities —		
Depreciation and amortization, total	**34,887**	33,580
Deferred income taxes	**9,917**	8,601
Convertible investment tax credits	**(3,900)**	38,068
Deferred revenues	**(16,686)**	(21,476)
Mark-to-market adjustments	**6,467**	(63)
Other, net	**1,326**	1,752
Changes in certain current assets and liabilities —		
-Receivables	**12,400**	20,759
-Fossil fuel stock	**(755)**	625
-Materials and supplies	**(1,167)**	253
-Prepaid income taxes	**(5,105)**	15,744
-Other current assets	**(2,083)**	(137)
-Accounts payable	**(14,590)**	(21,645)
-Accrued taxes	**4,375**	4,888
-Accrued interest	**(10,172)**	(12,281)
-Other current liabilities	**(2)**	(519)
Net cash provided from operating activities	**44,228**	105,892
Investing Activities:		
Property additions	**(32,450)**	(113,518)
Change in construction payables	**(999)**	43,259
Payments pursuant to long-term service agreements	**(11,415)**	(11,320)
Other investing activities	**(2,848)**	(3,165)
Net cash used for investing activities	**(47,712)**	(84,744)
Financing Activities:		
Increase (decrease) in notes payable, net	**20,165**	(20,360)
Proceeds — Capital contributions	**1,219**	17,179
Repayments — Other long-term debt	**(150)**	(3,066)
Payment of common stock dividends	**(31,750)**	(22,800)
Other financing activities	**25**	38
Net cash used for financing activities	**(10,491)**	(29,009)
Net Change in Cash and Cash Equivalents	**(13,975)**	(7,861)
Cash and Cash Equivalents at Beginning of Period	**16,943**	14,204
Cash and Cash Equivalents at End of Period	**$ 2,968**	$ 6,343
Supplemental Cash Flow Information:		
Cash paid during the period for —		
Interest (net of $6,556 and $4,240 capitalized for 2012 and 2011, respectively)	**$ 20,966**	$ 26,993
Income taxes (net of refunds)	**10,820**	(44,721)
Noncash transactions — accrued property additions at end of period	**31,591**	78,567

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Assets	At March 31, 2012	At December 31, 2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 2,968**	$ 16,943
Receivables —		
Customer accounts receivable	**58,192**	59,360
Other accounts receivable	**1,779**	2,122
Affiliated companies	**25,609**	36,508
Fossil fuel stock, at average cost	**13,793**	13,038
Materials and supplies, at average cost	**38,769**	37,603
Prepaid service agreements — current	**27,234**	28,621
Prepaid income taxes	**19,050**	5,192
Other prepaid expenses	**6,095**	4,645
Assets from risk management activities	**89**	177
Total current assets	**193,578**	204,209
Property, Plant, and Equipment:		
In service	**3,158,331**	3,167,840
Less accumulated provision for depreciation	**680,297**	652,087
Plant in service, net of depreciation	**2,478,034**	2,515,753
Construction work in progress	**737,751**	666,280
Total property, plant, and equipment	**3,215,785**	3,182,033
Other Property and Investments:		
Goodwill	**1,839**	1,839
Other intangible assets, net of amortization of $1,671 and $1,476 at March 31, 2012 and December 31, 2011, respectively	**47,448**	47,644
Total other property and investments	**49,287**	49,483
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**104,959**	115,838
Other deferred charges and assets — affiliated	**2,969**	3,029
Other deferred charges and assets — non-affiliated	**29,451**	26,385
Total deferred charges and other assets	**137,379**	145,252
Total Assets	**$ 3,596,029**	$ 3,580,977

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

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SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

Liabilities and Stockholder's Equity	At March 31, 2012	At December 31, 2011
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 550**	$ 555
Notes payable — non-affiliated	**199,685**	179,520
Accounts payable —		
Affiliated	**42,838**	63,609
Other	**49,762**	44,321
Accrued taxes —		
Accrued income taxes	**1,260**	2,548
Other accrued taxes	**5,812**	2,158
Accrued interest	**11,702**	21,874
Liabilities from risk management activities	**16,447**	9,651
Other current liabilities	**17,470**	7,401
Total current liabilities	**345,526**	331,637
Long-term Debt	**1,302,620**	1,302,758
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**333,698**	319,790
Deferred convertible investment tax credits	**128,411**	125,065
Deferred capacity revenues — affiliated	**4,658**	20,637
Other deferred credits and liabilities — affiliated	**3,359**	3,618
Other deferred credits and liabilities — non-affiliated	**5,130**	4,965
Total deferred credits and other liabilities	**475,256**	474,075
Total Liabilities	**2,123,402**	2,108,470
Redeemable Noncontrolling Interest	**3,923**	3,825
Common Stockholder's Equity:		
Common stock, par value $.01 per share —		
Authorized - 1,000,000 shares		
Outstanding - 1,000 shares	**—**	—
Paid-in capital	**1,029,430**	1,028,210
Retained earnings	**444,867**	447,301
Accumulated other comprehensive loss	**(5,593)**	(6,829)
Total common stockholder's equity	**1,468,704**	1,468,682
Total Liabilities and Stockholder's Equity	**$ 3,596,029**	$ 3,580,977

The accompanying notes as they relate to Southern Power are an integral part of these condensed financial statements.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRST QUARTER 2012 vs. FIRST QUARTER 2011

OVERVIEW

Southern Power and its wholly-owned subsidiaries construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based prices in the wholesale market. Southern Power continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into PPAs primarily with investor owned utilities, independent power producers, municipalities, and electric cooperatives.

To evaluate operating results and to ensure Southern Power's ability to meet its contractual commitments to customers, Southern Power focuses on several key performance indicators. These indicators include peak season equivalent forced outage rate (Peak Season EFOR), contract availability, and net income. Peak Season EFOR defines the hours during peak demand times when Southern Power's generating units are not available due to forced outages (the lower the better). Contract availability measures the percentage of scheduled hours that a unit was available. Net income is the primary measure of Southern Power's financial performance. For additional information on these indicators, see MANAGEMENT'S DISCUSSION AND ANALYSIS — OVERVIEW — "Key Performance Indicators" of Southern Power in Item 7 of the Form 10-K.

RESULTS OF OPERATIONS

Net Income

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(8.4)	(22.3)

Southern Power's net income for the first quarter 2012 was $29.3 million compared to $37.7 million for the corresponding period in 2011. The decrease was primarily due to a decrease in energy revenues from existing PPAs, a decrease in capacity revenues due to a reduction in total MWs of capacity under long-term contracts, and an increase in other operations and maintenance expenses. The decrease was partially offset by an increase in energy revenues from sales to affiliates under the IIC, lower fuel expenses, lower interest expenses, and lower income taxes.

Wholesale Revenues — Non-Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(56.6)	(28.7)

Wholesale energy sales to non-affiliates will vary depending on the energy demand of those customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of Southern Power's energy. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Wholesale revenues from non-affiliates for the first quarter 2012 were $140.6 million compared to $197.2 million for the corresponding period in 2011. The decrease was primarily due to a $60.5 million decrease in energy sales, reflecting a 12.3% decrease in KWH sales and a 43.3% decrease in the average price of energy. The decrease in revenue from energy sales was partially offset by a $3.9 million increase in capacity revenue due to an increase in the total MWs of capacity under contract with non-affiliates.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Power Sales Agreements" of Southern Power in Item 7 of the Form 10-K for additional information.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Wholesale Revenues — Affiliates

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$28.5	34.2

Wholesale energy sales to affiliated companies within the Southern Company system will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the FERC.

Wholesale revenues from affiliates for the first quarter 2012 were $111.8 million compared to $83.3 million for the corresponding period in 2011. The increase was primarily the result of a $41.8 million increase in energy sales under the IIC, reflecting a 314.1% increase in KWH sales, partially offset by a 43.3% reduction in the average price of energy. The increase in revenue from energy sales was partially offset by an $11.9 million decrease in capacity revenue due to a decrease in total MWs of capacity under contract with affiliates.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Power Sales Agreements" of Southern Power in Item 7 of the Form 10-K for additional information.

Fuel and Purchased Power Expenses

	First Quarter 2012 vs. First Quarter 2011	
	(change in millions)	*(% change)*
Fuel	$(13.6)	(13.3)
Purchased power — non-affiliates	11.7	130.9
Purchased power — affiliates	(12.7)	(84.5)
Total fuel and purchased power expenses	$(14.6)	

Southern Power PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel costs is generally accompanied by an increase or decrease in related fuel revenues and does not have a significant impact on net income. Southern Power is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources available throughout the Southern Company system and other contract resources. Load requirements are submitted to the Power Pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by Southern Power, affiliate-owned generation, or external purchases.

In the first quarter 2012, total fuel and purchased power expenses were $112.1 million compared to $126.8 million for the corresponding period in 2011. Fuel and purchased power expenses decreased $64.0 million due to a 38.8% decrease in the average cost of fuel and a 26.0% decrease in the average cost of purchased power. The decrease was partially offset by a $49.4 million increase associated with a 39.4% increase in volume of KWHs generated and purchased.

In the first quarter 2012, fuel expense was $89.1 million compared to $102.7 million for the corresponding period in 2011. Fuel expense decreased $56.0 million associated with a 38.8% decrease in the average cost of fuel. The decrease was partially offset by a $42.4 million increase associated with a 41.3% increase in the volume of KWHs generated.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
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In the first quarter 2012, purchased power expense was $23.0 million compared to $24.0 million for the corresponding period in 2011. Purchased power expenses decreased $8.0 million due to a 26.0% decrease in the average cost of purchased power, partially offset by a $7.0 million increase associated with a 29.2% increase in the volume of KWHs purchased.

Other Operations and Maintenance Expenses

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$5.7	13.2

In the first quarter 2012, other operations and maintenance expenses were $48.4 million compared to $42.7 million for the corresponding period in 2011. The increase was primarily due to a $3.4 million increase in administrative and general expenses primarily due to increases in business development expenses and affiliate service company expense allocated based on load and fuel burn and a $1.8 million increase related to a scheduled outage at Plant Rowan.

Interest Expense, Net of Amounts Capitalized

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(5.2)	(27.5)

In the first quarter 2012, interest expense, net of amounts capitalized was $13.6 million compared to $18.8 million for the corresponding period in 2011. The decrease was primarily due to a $2.2 million expense reduction associated with the refinancing of $575 million in long-term debt in 2011 and a $2.3 million increase in capitalized interest associated with the construction of the Cleveland County combustion turbine generating plant and the Nacogdoches biomass plant. See FUTURE EARNINGS POTENTIAL — "Construction Projects" herein for additional information.

Income Taxes

First Quarter 2012 vs. First Quarter 2011	
(change in millions)	*(% change)*
$(7.4)	(35.6)

In the first quarter 2012, income taxes were $13.4 million compared to $20.8 million for the corresponding period in 2011. The decrease was primarily due to lower pre-tax earnings.

FUTURE EARNINGS POTENTIAL

The results of operations discussed above are not necessarily indicative of Southern Power's future earnings potential. The level of Southern Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Power's competitive wholesale business. These factors include: Southern Power's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in Southern Power's target market areas; the successful remarketing of capacity as current contracts expire; and Southern Power's ability to execute its acquisition strategy and to construct generating facilities. Other factors that could influence future earnings include weather, demand, generation patterns, and operational limitations. General economic conditions have lowered demand and have negatively impacted capacity revenues under Southern Power's PPAs where the amounts purchased are based on demand. Southern Power is unable to predict whether demand under these PPAs will return to pre-recession levels. The timing and extent of the economic recovery is uncertain and will impact future earnings. For additional information relating to these issues, see RISK FACTORS in Item 1A and MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL of Southern Power in Item 7 of the Form 10-K.

Environmental Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters" of Southern Power in Item 7 of the Form 10-K for information on the development by federal and state environmental regulatory agencies of additional control strategies for emissions of air pollution from industrial sources, including electric generating facilities. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, or other environmental and health concerns could also significantly affect Southern Power. While Southern Power's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Climate Change Litigation

Hurricane Katrina Case

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL — "Environmental Matters — Climate Change Litigation — Hurricane Katrina Case" of Southern Power in Item 7 and Note 3 to the financial statements of Southern Power under "Climate Change Litigation — Hurricane Katrina Case" in Item 8 of the Form 10-K for additional information. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the amended class action complaint filed on May 27, 2011 by the plaintiffs. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The ultimate outcome of this matter cannot be determined at this time.

Global Climate Issues

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Environmental Matters — Global Climate Issues" of Southern Power in Item 7 of the Form 10-K for additional information. On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. As proposed, the standards would not apply to existing units. The EPA has delayed its plans to propose greenhouse gas emissions performance standards for modified sources and emissions guidelines for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Income Tax Matters

Bonus Depreciation

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Southern Power through 2013. Consequently, Southern Power's positive cash flow benefit is estimated to be between $140 million and $185 million in 2012.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Construction Projects

Cleveland County Units 1-4

In 2008, Southern Power announced that it will build an electric generating plant in Cleveland County, North Carolina. The plant will consist of four combustion turbine natural gas generating units with a total generating capacity of 720 MWs. The units are expected to begin commercial operation in December 2012. Construction costs incurred through March 31, 2012 were $277.4 million. The total estimated cost of the project is expected to be between $335 million and $365 million.

Nacogdoches Biomass Plant

In 2009, Southern Power acquired all of the outstanding membership interests of Nacogdoches Power, LLC (Nacogdoches) from American Renewables LLC, the original developer of the project. Nacogdoches is constructing a biomass generating plant in Sacul, Texas with an estimated capacity of 100 MWs. The generating plant will be fueled from wood waste. Construction commenced in 2009 and the plant is expected to begin commercial operation in June 2012. Construction costs incurred through March 31, 2012 were $406.4 million. The total estimated cost of the project is expected to be between $470 million and $490 million.

Power Sales Agreements

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Power Sales Agreements" of Southern Power in Item 7 of the Form 10-K for additional information regarding Southern Power's PPAs with investor-owned utilities, independent power purchasers, municipalities, and electric cooperatives.

In June 2011, Southern Power entered into three PPAs with Georgia Power subject to Georgia PSC and FERC approval. These PPAs were approved by the Georgia PSC on March 20, 2012 and are still subject to approval by the FERC. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Power is subject to certain claims and legal actions arising in the ordinary course of business. Southern Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against Southern Power and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of Southern Power in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Power's financial statements.

See the Notes to the Condensed Financial Statements herein for a discussion of various other contingencies and other matters being litigated which may affect future earnings potential.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Power prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements of Southern Power in Item 8 of the Form 10-K. In the application of these policies, certain estimates are made that may have a material impact on Southern Power's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. See MANAGEMENT'S DISCUSSION AND ANALYSIS — ACCOUNTING POLICIES — "Application of Critical Accounting Policies and Estimates" of Southern Power in Item 7 of the Form 10-K for a complete discussion of Southern Power's critical accounting policies and estimates related to Revenue Recognition, Impairment of Long Lived Assets and Intangibles, Acquisition Accounting, Contingent Obligations, Depreciation, and Convertible Investment Tax Credits (ITCs).

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Power's financial condition remained stable at March 31, 2012. Southern Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $44.2 million for the first three months of 2012 compared to $105.9 million for the corresponding period in 2011. This decrease was mainly due to the effect of cash received in 2011 for convertible ITCs. Net cash used for investing activities totaled $47.7 million for the first three months of 2012 compared to $84.7 million for the corresponding period in 2011. This decrease was primarily due to a decrease in CWIP expenditures related to construction activities at Cleveland County and Nacogdoches. Net cash used for financing activities totaled $10.5 million for the first three months of 2012 compared to $29.0 million for the corresponding period in 2011. This decrease was primarily due to a net repayment of notes payable in 2011 compared to an increase in notes payable in 2012, partially offset by a decrease in capital contributions from Southern Company and an increase in dividends paid.

Significant asset changes in the balance sheet for the first quarter 2012 include: a $14.0 million decrease in cash and cash equivalents; a $10.9 million decrease in accounts receivables from affiliated companies primarily due to a decrease in the amount due for energy sales under the IIC; a $13.9 million increase in prepaid income taxes; a $71.5 million increase in CWIP due to Cleveland County and Nacogdoches construction activities and capital equipment replacements during outages in progress; and a $12.3 million decrease in prepaid long-term service agreements due to costs incurred related to scheduled plant maintenance.

Significant liability and stockholder's equity changes in the balance sheet for the first quarter 2012 include: a $20.2 million increase in notes payable non-affiliated primarily due to the timing of operating cash flows; a $20.8 million decrease in accounts payable — affiliated primarily due to timing of payments to service company affiliates; a $10.2 million decrease in accrued interest due to scheduled debt service; and a $16.0 million decrease in deferred capacity revenues — affiliated due to seasonality.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Capital Requirements and Contractual Obligations

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Capital Requirements and Contractual Obligations" of Southern Power in Item 7 of the Form 10-K for a description of Southern Power's capital requirements for its construction program, scheduled maturities of long-term debt, interest, leases, derivative obligations, purchase commitments, and long-term service agreements. There are no requirements through March 31, 2013 to fund maturities of long-term debt.

The construction program is subject to periodic review and revision; these amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements and work to be performed under long-term service agreements. Planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

Sources of Capital

Southern Power may use operating cash flows, external funds, or equity capital or loans from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. Southern Power expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Sources of Capital" of Southern Power in Item 7 of the Form 10-K for additional information.

Southern Power's current liabilities frequently exceed current assets due to the use of short-term debt as a funding source, as well as cash needs which can fluctuate significantly due to the seasonality of the business. To meet liquidity and capital resource requirements, Southern Power had at March 31, 2012 cash and cash equivalents of approximately \$3.0 million and a committed credit facility of \$500 million (Facility) expiring in 2016. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to the indebtedness of Southern Power. Southern Power is currently in compliance with all such covenants. Proceeds from this Facility may be used for working capital and general corporate purposes as well as liquidity support for Southern Power's commercial paper program. See Note 6 to the financial statements of Southern Power under "Bank Credit Arrangements" in Item 8 of the Form 10-K and Note (E) to the Condensed Financial Statements under "Bank Credit Arrangements" herein for additional information.

Southern Power's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
March 31, 2012:					
Commercial paper	$200	0.5%	$193	0.4%	$226

(a) Average and maximum amounts are based upon daily balances during the period.

Management believes that the need for working capital can be adequately met by utilizing the commercial paper program, the line of credit, and cash.

Credit Rating Risk

Southern Power does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.

The maximum potential collateral requirements under these contracts at March 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	**$ 9**
At BBB- and/or Baa3	**454**
Below BBB- and/or Baa3	**1,218**

Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Southern Power's ability to access capital markets, particularly the short-term debt market.

In addition, through the acquisition of Plant Rowan, Southern Power assumed a PPA with North Carolina Municipal Power Agency No. 1 that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
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Market Price Risk

Southern Power is exposed to market risks, including changes in interest rates, certain energy-related commodity prices, and, occasionally, currency exchange rates. To manage the volatility attributable to these exposures, Southern Power takes advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Southern Power's policies in areas such as counterparty exposure and risk management practices. Southern Power's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

Southern Power's market risk exposure relative to interest rate changes for the first quarter 2012 has not changed materially compared with the December 31, 2011 reporting period. Since a significant portion of outstanding indebtedness bears interest at fixed rates, Southern Power is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Because energy from Southern Power's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts for the three months ended March 31, 2012 were as follows:

	First Quarter 2012 Changes
	Fair Value
	(in millions)
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (9.2)**
Contracts realized or settled	**0.8**
Current period changes [(a)]	**(7.7)**
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (16.1)**

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The decrease in the fair value positions of the energy-related derivative contracts for the three months ended March 31, 2012 was $6.9 million, which is due to both power and natural gas positions. This change is attributable to both the volume and prices of power and natural gas as follows:

	March 31, 2012	December 31, 2011
Power — net purchased or (sold)		
MWHs *(in millions)*	**(0.1)**	0.1
Weighted average contract cost per MWH above (below) market prices *(in dollars)*	**$(5.20)**	$(1.04)
Natural gas net purchased		
Commodity — million mmBtu	**28.2**	8.3
Commodity — weighted average contract cost per mmBtu above (below) market prices *(in dollars)*	**$1.57**	$1.18

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
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The fair value of energy-related derivative contracts by hedge designation reflected in the financial statements as assets (liabilities) consists of the following:

Asset (Liability) Derivatives	March 31, 2012	December 31, 2011
	(in millions)	
Cash flow hedges	**$ (1.2)**	$(0.8)
Not designated	**(14.9)**	(8.4)
Total fair value	**$(16.1)**	$(9.2)

Gains and losses on energy-related derivatives used by Southern Power to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the three months ended March 31, 2012 for energy-related derivative contracts that were not hedges were $(6.5) million and will continue to be marked to market until the settlement date. Included in this amount are gains (losses) on derivative contracts reimbursable by third parties in the amount of $(5.2) million. For the three months ended March 31, 2011, the total net unrealized pre-tax gains (losses) recognized in the statements of income for energy-related derivative contracts that were not hedges were not material.

Southern Power uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note (C) to the Condensed Financial Statements herein for further discussion on fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at March 31, 2012 were as follows:

	March 31, 2012 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(16.1)	(16.3)	(0.2)	0.4
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (16.1)	$ (16.3)	$ (0.2)	$ 0.4

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by Southern Power. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until all relevant regulations are finalized.

For additional information, see MANAGEMENT'S DISCUSSION AND ANALYSIS — FINANCIAL CONDITION AND LIQUIDITY — "Market Price Risk" of Southern Power in Item 7 and Note 1 under "Financial Instruments" and Note 9 to the financial statements of Southern Power in Item 8 of the Form 10-K and Note (H) to the Condensed Financial Statements herein.

Financing Activities

For the three months ended March 31, 2012, Southern Power did not issue or redeem any long-term securities.

During the three months ended March 31, 2012, Southern Power prepaid $0.2 million of long-term debt.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS
FOR
THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES

INDEX TO APPLICABLE NOTES TO
FINANCIAL STATEMENTS BY REGISTRANT

Registrant	Applicable Notes
Southern Company	A, B, C, D, E, F, G, H, I
Alabama Power	A, B, C, E, F, G, H
Georgia Power	A, B, C, E, F, G, H
Gulf Power	A, B, C, E, F, G, H
Mississippi Power	A, B, C, E, F, G, H
Southern Power	A, B, C, E, G, H

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES

NOTES TO THE CONDENSED FINANCIAL STATEMENTS:

(A) INTRODUCTION

The condensed quarterly financial statements of each registrant included herein have been prepared by such registrant, without audit, pursuant to the rules and regulations of the SEC. The Condensed Balance Sheets as of December 31, 2011 have been derived from the audited financial statements of each registrant. In the opinion of each registrant's management, the information regarding such registrant furnished herein reflects all adjustments, which, except as otherwise disclosed, are of a normal recurring nature, necessary to present fairly the results of operations for the periods ended March 31, 2012 and 2011. Certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations, although each registrant believes that the disclosures regarding such registrant are adequate to make the information presented not misleading. Disclosures which would substantially duplicate the disclosures in the Form 10-K and details which have not changed significantly in amount or composition since the filing of the Form 10-K are generally omitted from this Quarterly Report on Form 10-Q. Therefore, these Condensed Financial Statements should be read in conjunction with the financial statements and the notes thereto included in the Form 10-K. Due to the seasonal variations in the demand for energy, operating results for the periods presented are not necessarily indicative of the operating results to be expected for the full year.

Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Investments in Leveraged Leases

See Note 1 to the financial statements of Southern Company under "Leveraged Leases" in Item 8 of the Form 10-K for additional information.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the assets. Southern Company is currently engaged in discussions with the lessee and the holders of the project's nonrecourse debt to restructure the debt payments and the related rental payments to allow additional capital investment in the project to be made to improve the operation of the generation assets and the financial viability of the lease transaction. Southern Company continues to monitor the performance of the underlying assets and to evaluate the ability of the lessee to continue to make the required lease payments. If the attempts at restructuring the project are unsuccessful and the project is ultimately abandoned, the potential impairment loss that would be incurred is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

(B) CONTINGENCIES AND REGULATORY MATTERS

See Note 3 to the financial statements of the registrants in Item 8 of the Form 10-K for information relating to various lawsuits, other contingencies, and regulatory matters.

General Litigation Matters

Each registrant is subject to certain claims and legal actions arising in the ordinary course of business. In addition, business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, have become more frequent. The ultimate outcome of such pending or potential litigation against each registrant and any subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements of each registrant in Item 8 of the Form 10-K, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on such registrant's financial statements.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the NSR provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In September 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. On March 14, 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power (including claims related to a unit co-owned by Mississippi Power). At the same time, the EPA asked the U.S. Court of Appeals for the Eleventh Circuit to stay its appeal of the judgment in favor of Alabama Power. Alabama Power filed oppositions to the EPA's motion and its request for a stay. On March 29, 2012, the U.S. Court of Appeals for the Eleventh Circuit denied the EPA's request to stay its appeal. The U.S. District Court for the Northern District of Alabama has not ruled on the EPA's motion seeking vacatur of the judgment.

Southern Company and each traditional operating company believe each such traditional operating company complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether Southern Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. On May 27, 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. Each Southern Company entity named in the lawsuit believes that these claims are without merit. While each Southern Company entity named in the lawsuit believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether any Southern Company entity named in the lawsuit will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of March 31, 2012 was $20 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

In 2008, the EPA advised Georgia Power that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices regarding this site from the EPA.

On September 29, 2011, the EPA issued a unilateral administrative order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the Ward Transformer Superfund site. Georgia Power does not believe it is a liable party under CERCLA based on its alleged connection to the site. As a result, on November 7, 2011, Georgia Power filed a response with the EPA indicating that Georgia Power is not willing to undertake the work set forth in the UAO because Georgia Power has sufficient cause to believe it is not a liable party. On November 22, 2011, the EPA sent Georgia Power a letter stating that the EPA does not consider Georgia Power to be in compliance with the UAO. The EPA also stated that it is considering enforcement options against Georgia Power and other UAO recipients who are not complying with the UAO.

The EPA may seek to enforce the UAO in court pursuant to its enforcement authority under CERCLA and may seek recovery of its costs in undertaking the UAO work. If the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party’s failure to comply with the UAO.

In addition to the EPA’s action at the Ward Transformer Superfund site, in 2009, Georgia Power, along with many other parties, was sued by several existing PRPs for cost recovery for a removal action that is currently taking place. Georgia Power and numerous other defendants moved for a dismissal of these lawsuits. The court denied the dismissal of the lawsuits in March 2010 but granted Georgia Power’s motion regarding the dismissal of the claim pertaining to the plaintiffs’ joint and several liability.

The ultimate outcome of the Brunswick CERCLA NPL and Ward Transformer Superfund site matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the regulatory treatment, it is not expected to have a material impact on Southern Company’s or Georgia Power’s financial statements.

Gulf Power’s environmental remediation liability includes estimated costs of environmental remediation projects of approximately $60 million as of March 31, 2012. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power’s environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

In 2003, the Texas Commission on Environmental Quality (TCEQ) designated Mississippi Power as a potentially responsible party at a site in Texas. The site was owned by an electric transformer company that handled Mississippi Power’s transformers as well as those of many other entities. The site owner is bankrupt and the State of Texas has entered into an agreement with Mississippi Power and several other utilities to investigate and remediate the site. The feasibility study/presumptive remedy document was originally filed with TCEQ in June 2011 and remains under consideration by the agency. Amounts expensed and accrued related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter on Mississippi Power will depend upon further environmental assessment and the ultimate number of potentially responsible parties. The remediation expenses incurred by Mississippi Power are expected to be recovered through the ECO Plan.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management of Southern Company, Georgia Power, Gulf Power, and Mississippi Power does not believe that additional liabilities, if any, at these sites would be material to their respective financial statements .

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

Nuclear Fuel Disposal Cost Litigation

Alabama Power and Georgia Power have contracts with the U.S., acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and Alabama Power and Georgia Power are pursuing legal remedies against the government for breach of contract.

In 2007, the U.S. Court of Federal Claims awarded Georgia Power approximately $30 million, based on its ownership interests, and awarded Alabama Power approximately $17 million, representing substantially all of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004.

In 2008, the government filed an appeal and, on March 11, 2011, the U.S. Court of Appeals for the Federal Circuit issued an order in which it affirmed the damage award to Alabama Power, but remanded the Georgia Power portion of the proceeding back to the U.S. Court of Federal Claims for reconsideration of the damages amount in light of the spent nuclear fuel acceptance rates adopted in a separate proceeding by the U.S. Court of Appeals for the Federal Circuit. On July 12, 2011, the court entered final judgment in favor of Alabama Power and awarded Alabama Power approximately $17 million. In April 2012, the award was credited to cost of service for the benefit of Alabama Power customers.

On April 5, 2012, Georgia Power and the government entered into a stipulation to conclude this litigation, which provided for judgment in favor of Georgia Power and awarded Georgia Power approximately $27 million in damages, based on its ownership interests. On April 5, 2012, the stipulation was approved by the U.S. Court of Federal Claims. The proceeds will be credited to the Georgia Power accounts where the original costs were charged and will be used to reduce rate base, fuel, and cost of service for the benefit of Georgia Power customers.

In 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim) due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of March 31, 2012 for the second claim. The final outcome of this matter cannot be determined at this time.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

See Note 3 to the financial statements of Mississippi Power under "FERC Matters" in Item 8 of the Form 10-K for additional information regarding Mississippi Power's request for revised rates related to the wholesale Municipal and Rural Associations (MRA) cost-based electric tariff. See Note 3 to the financial statements of Southern Company and of Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 of the Form 10-K for information regarding Mississippi Power's construction of the Kemper IGCC.

On January 20, 2012, Mississippi Power reached a settlement agreement with its wholesale customers, which was executed by all parties on March 9, 2012. The settlement agreement provides that base rates under the cost-based electric tariff will increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. In 2012, the amount of base rate revenues to be received from the agreed upon increase will be approximately $17.0 million. On March 12, 2012, Mississippi Power filed an unopposed motion to place wholesale MRA interim rates into effect pending approval of the settlement agreement between the parties by the FERC. On March 28, 2012, the FERC approved the motion to place interim rates into effect beginning in May 2012. Approval of the settlement agreement by the FERC has been delayed until later in the year.

The ultimate outcome of this matter cannot be determined at this time.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

Retail Regulatory Matters

Georgia Power

Fuel Cost Recovery

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters — Georgia Power — Fuel Cost Recovery" and "Retail Regulatory Matters — Fuel Cost Recovery," respectively, in Item 8 of the Form 10-K for additional information.

As of March 31, 2012, Georgia Power had a total over recovered fuel cost balance of approximately $22 million compared to an under recovered balance of $137 million at December 31, 2011. The over recovered fuel costs at March 31, 2012 are included in other deferred credits and liabilities on Southern Company's and Georgia Power's Condensed Balance Sheets herein. The under recovered fuel costs at December 31, 2011 are included in current assets on Southern Company's and Georgia Power's Condensed Balance Sheets herein. Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, any changes in the billing factor will not have a significant effect on Southern Company's or Georgia Power's revenues or net income, but will affect cash flow.

On March 30, 2012, Georgia Power filed a request with the Georgia PSC to decrease fuel rates by 19%, which is expected to reduce annual billings by $567 million. The decrease in fuel costs is driven primarily by lower natural gas prices as a result of increased natural gas supplies. The Georgia PSC is scheduled to vote on this matter on June 21, 2012. As proposed, the rate decrease would become effective July 1, 2012; however, Georgia Power is currently working with the Georgia PSC to potentially implement the proposed decrease effective June 1, 2012. The ultimate outcome of this matter cannot be determined at this time.

2011 Integrated Resource Plan Update

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters — Georgia Power — 2011 Integrated Resource Plan Update" and "Retail Regulatory Matters — 2011 Integrated Resource Plan Update," respectively, in Item 8 of the Form 10-K for additional information.

On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire two coal-fired generation units at Plant Branch as of October 31, 2013 and December 31, 2013 and an oil-fired unit at Plant Mitchell as of March 26, 2012, which was included in Georgia Power's 2011 IRP Update. The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. The PPAs remain subject to FERC approval. The ultimate outcome of this matter cannot be determined at this time.

Nuclear Construction

See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters — Georgia Power — Nuclear Construction" and "Construction — Nuclear," respectively, in Item 8 of the Form 10-K for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4.

On February 16, 2012, a group of petitioners who had intervened in the NRC's combined construction and operating licenses (COLs) proceedings for Plant Vogtle Units 3 and 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the NRC's issuance of the COLs. In addition, on February 16, 2012, another group of petitioners filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's certification of the Westinghouse Design Certification Document, as amended (DCD). On April 3, 2012, the U.S. Court of Appeals for the District of Columbia Circuit granted a motion filed by these two groups of petitioners to consolidate their challenges. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the order issuing the COLs for Plant Vogtle Units 3 and 4 with the U.S. District Court for the

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

District of Columbia. Georgia Power has filed a motion to intervene in these proceedings and intends to vigorously contest these petitions.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related CWIP accounts in rate base. Also in 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows Georgia Power to recover financing costs for nuclear construction projects by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows Georgia Power to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered Georgia Power to report against this total certified cost of approximately $6.1 billion. In addition, in December 2010, the Georgia PSC approved Georgia Power’s NCCR tariff. The NCCR tariff became effective January 1, 2011 and adjustments are filed with the Georgia PSC on November 1 of each year to become effective on January 1 of the following year. Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At March 31, 2012, approximately $68 million of these 2009 and 2010 costs remained in CWIP.

Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners) and Westinghouse and Stone & Webster, Inc. (collectively, Consortium) have established both informal and formal dispute resolution procedures in accordance with the engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 MWs each and related facilities, structures, and improvements at Plant Vogtle entered into by the parties (Vogtle 3 and 4 Agreement) in order to resolve issues arising during the course of constructing a project of this magnitude. The Consortium and Georgia Power (on behalf of the Owners) have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including costs associated with design changes to the DCD, and costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs. The Owners and the Consortium have begun negotiations regarding these issues, including the assertion by the Consortium that the Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. In preliminary discussions, the Consortium has provided its initial estimate of its proposed adjustment to the contract price. The Consortium’s estimated adjustment attributable to Georgia Power (based on Georgia Power’s ownership interest) is approximately $400 million (in 2008 dollars) with respect to these issues, which include an initial estimate of costs for efforts to maintain the projected in-service dates of 2016 and 2017 for Plant Vogtle Units 3 and 4, respectively. Georgia Power has not agreed with the amount of these proposed adjustments or that the Owners have responsibility for any costs related to these issues. Georgia Power expects negotiations with the Consortium to continue over the next several months during which time the parties will attempt to reach a mutually acceptable compromise of their positions. If a compromise cannot be reached, formal dispute resolution, including litigation, may follow. Georgia Power intends to vigorously defend its positions. If these costs are imposed upon the Owners, Georgia Power would seek an amendment to the certified cost of Plant Vogtle Units 3 and 4, if necessary. Additional claims by the Consortium or Georgia Power (on behalf of the Owners) are expected to arise throughout the construction of Plant Vogtle Units 3 and 4.

In addition, there are processes in place to assure compliance with the design requirements specified in the DCD and the COLs, including rigorous inspection by Southern Nuclear and the NRC that occurs throughout construction. A recent routine NRC inspection identified that certain details of the rebar construction in the Plant Vogtle Unit 3 nuclear island were not consistent with the DCD. Georgia Power expects to receive official notice of these findings from the NRC. Georgia Power, on behalf of the Owners, is currently engaged in constructive discussions with the Consortium to identify appropriate corrective actions. Various inspection issues are expected as construction proceeds.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including legal challenges to the NRC issuance of the COLs and certification of the DCD. Similar additional challenges at the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time.

Other Construction

See Note 3 to the financial statements of Southern Company and Georgia Power under “Retail Regulatory Matters — Georgia Power — Other Construction” and “Construction — Other Construction,” respectively, in Item 8 of the Form 10-K for additional information.

Georgia Power placed Plant McDonough Unit 5 into service on April 26, 2012. Plant McDonough Unit 6 is expected to be placed into service in November 2012. Plant McDonough Unit 1 was retired on February 29, 2012.

Gulf Power

Retail Base Rate Case

See Note 3 to the financial statements of Gulf Power under “Retail Regulatory Matters — Retail Base Rate Case” in Item 8 of the Form 10-K for additional information.

On March 12, 2012, the Florida PSC approved a permanent increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the permanent increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC’s decision on the amount of the permanent increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. Gulf Power’s authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to Gulf Power’s retail base rates and charges of $4 million to be effective in January 2013. On April 18, 2012, Gulf Power filed a motion to reconsider one aspect of the decision dealing with property acquired as a potential site for a future generating plant. If the motion is granted, the previously approved rates would be increased by an additional $2 million. The ultimate outcome of this matter cannot be determined at this time.

Cost Recovery Clauses

See Note 3 to the financial statements of Gulf Power under “Retail Regulatory Matters — Cost Recovery Clauses” in Item 8 of the Form 10-K for additional information.

Fuel Cost Recovery

See Notes 1 and 3 to the financial statements of Gulf Power under “Revenues” and “Retail Regulatory Matters — Fuel Cost Recovery,” respectively, in Item 8 of the Form 10-K for additional information.

Over recovered fuel costs at March 31, 2012 totaled $28.8 million compared to $9.9 million at December 31, 2011. These amounts are included in other regulatory liabilities, current on Gulf Power’s Condensed Balance Sheets herein.

Purchased Power Capacity Recovery

See Notes 1 and 3 to the financial statements of Gulf Power under “Revenues” and “Retail Regulatory Matters — Purchased Power Capacity Recovery,” respectively, in Item 8 of the Form 10-K for additional information.

Over recovered purchased power capacity costs at March 31, 2012 totaled $9.6 million compared to $8.0 million at December 31, 2011. These amounts are included in other regulatory liabilities, current on Gulf Power’s Condensed Balance Sheets herein.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

Environmental Cost Recovery

See Note 3 to the financial statements of Gulf Power under “Retail Regulatory Matters — Environmental Cost Recovery” in Item 8 of the Form 10-K for additional information.

Over recovered environmental costs at March 31, 2012 totaled $4.0 million compared to $10.0 million at December 31, 2011. These amounts are included in other regulatory liabilities, current on Gulf Power’s Condensed Balance Sheets herein.

On April 3, 2012, the Mississippi PSC approved Mississippi Power’s request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, excluding AFUDC, and it is scheduled for completion in December 2015.

Energy Conservation Cost Recovery

See Note 3 to the financial statements of Gulf Power under “Retail Regulatory Matters — Energy Conservation Cost Recovery” in Item 8 of the Form 10-K for additional information.

Under recovered energy conservation costs at March 31, 2012 totaled $2.0 million compared to $3.1 million at December 31, 2011. These amounts are included in under recovered regulatory clause revenues on Gulf Power’s Condensed Balance Sheets herein.

Mississippi Power

Performance Evaluation Plan

See Note 3 to the financial statements of Mississippi Power under “Retail Regulatory Matters — Performance Evaluation Plan” in Item 8 of the Form 10-K for additional information regarding Mississippi Power’s base rates.

On April 2, 2012, Mississippi Power filed a motion to suspend the 2011 PEP lookback filing. Unresolved matters related to certain costs included in the 2010 PEP lookback filing also impact the 2011 PEP lookback filing, making it impractical to determine Mississippi Power’s actual retail return on investment for 2011 for purposes of the 2011 PEP lookback filing. The ultimate outcome of these matters cannot be determined at this time.

System Restoration Rider

See Note 3 to the financial statements of Mississippi Power under “Retail Regulatory Matters — System Restoration Rider” in Item 8 of the Form 10-K for additional information.

On February 2, 2012, Mississippi Power submitted its 2012 System Restoration Rider (SRR) rate filing with the Mississippi PSC, which proposed that the 2012 SRR rate level remain at zero and Mississippi Power be allowed to accrue approximately $3.7 million to the property damage reserve in 2012. On April 3, 2012, the filing was approved by the Mississippi PSC.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

Environmental Compliance Overview Plan

See Note 3 to the financial statements of Mississippi Power under “Retail Regulatory Matters — Environmental Compliance Overview Plan” in Item 8 of the Form 10-K for information on Mississippi Power’s annual environmental filing with the Mississippi PSC.

On April 3, 2012, the Mississippi PSC approved Mississippi Power’s request for a CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with Mississippi Power’s portion being $330 million, excluding AFUDC. The project is scheduled for completion in December 2015. Mississippi Power’s portion of the cost is expected to be recovered through the ECO Plan. As of March 31, 2012, total project expenditures were $55.6 million, with Mississippi Power’s portion being $27.8 million.

On February 14, 2012, Mississippi Power submitted its 2012 ECO Plan notice, which proposed a 0.3% increase in annual revenues for Mississippi Power. In compliance with the CPCN to construct scrubbers on Plant Daniel Units 1 and 2, Mississippi Power will revise the 2012 ECO Plan notice excluding scrubber expenditures from rate base, which is expected to result in little or no rate change.

The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

See Note 3 to the financial statements of Mississippi Power under “Retail Regulatory Matters — Fuel Cost Recovery” in Item 8 of the Form 10-K for information regarding Mississippi Power’s fuel cost recovery.

At March 31, 2012, the amount of over recovered retail fuel costs included in Mississippi Power’s Condensed Balance Sheets herein was $50.9 million compared to $42.4 million at December 31, 2011. Mississippi Power also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. At March 31, 2012, the amount of over recovered wholesale MRA and MB fuel costs included in Mississippi Power’s Condensed Balance Sheets herein was $18.1 million and $2.4 million, respectively, compared to $14.3 million and $2.2 million, respectively, at December 31, 2011. In addition, at March 31, 2012 and December 31, 2011, the amount of over recovered MRA emissions allowance cost included in Mississippi Power’s Condensed Balance Sheets herein was $1.7 million. Mississippi Power’s operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this decrease to the billing factors will have no significant effect on Mississippi Power’s revenues or net income, but will decrease annual cash flow.

Integrated Coal Gasification Combined Cycle

See Note 3 to the financial statements of Southern Company and Mississippi Power under “Integrated Coal Gasification Combined Cycle” in Item 8 of the Form 10-K for information regarding Mississippi Power’s construction of the Kemper IGCC.

In May 2010, Mississippi Power filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming Mississippi Power’s application for a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN (2010 MPSC Order).

In June 2010, the Sierra Club filed an appeal of the Mississippi PSC’s June 2010 decision to grant the CPCN for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, in July 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. In October 2010, the Mississippi Supreme Court dismissed the Sierra Club’s direct appeal. On February 28, 2011, the Chancery Court issued a judgment affirming the 2010 MPSC Order and, on March 1, 2011, the Sierra Club appealed the Chancery Court’s decision to the Mississippi Supreme Court. On March 15, 2012, the Mississippi Supreme Court reversed the Chancery Court’s decision and the 2010 MPSC Order and remanded the matter to the Mississippi PSC to correct the 2010 MPSC Order. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN.

On March 30, 2012, the Mississippi PSC issued temporary authorization for the continuation of construction of the Kemper IGCC until the earlier of the conclusion of the Mississippi PSC's May 2012 open meeting or immediately upon the issuance of any final order issued by the Mississippi PSC on remand that conclusively addresses the mandate. On April 24, 2012, the Mississippi PSC issued a detailed order on remand (2012 MPSC Order) confirming the CPCN for the Kemper IGCC subject to the same conditions set forth in the 2010 MPSC Order. On April 26, 2012, the Sierra Club filed a motion for stay and a notice of appeal of the 2012 MPSC Order with the Chancery Court. On May 2, 2012, Mississippi Power filed a petition to join the appeal.

The certificated cost estimate of the Kemper IGCC is $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities. The 2012 MPSC Order, like the 2010 MPSC Order, (1) approved a construction cost cap of up to $2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the CO_2 pipeline facilities), (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's proposal, and (3) approved financing cost recovery on CWIP balances not to exceed the certificated cost estimate, which provided for the accrual of AFUDC in 2010 and 2011 and provides for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014, (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by Mississippi Power in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). As of March 31, 2012, Mississippi Power had utilized substantially all of its contingency contained in the certificated cost estimate. Mississippi Power anticipates that the costs to complete construction of the portion of the Kemper IGCC subject to the construction cost cap will be less than the cost cap but will likely exceed the certificated cost estimate.

The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. Of the total costs incurred through March 2009, $46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining $5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs has not been determined.

The Kemper IGCC plant, expected to begin commercial operation in May 2014, will use locally mined lignite (an abundant, lower heating value coal) from a mine adjacent to the plant as fuel. The mine is scheduled to be placed into service in June 2013. In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $245 million, of which $79.7 million has been incurred through March 31, 2012. The asset retirement obligation associated with the reclamation and restoration of the mine currently under construction was immaterial at March 31, 2012. In May 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. The contract with Liberty Fuels is effective June 2010 through the end of the mine reclamation. On December 13, 2011, the Mississippi Department of Environmental Quality (MDEQ) approved the surface coal mining and the water pollution control permits for the mining operations operated by Liberty Fuels. On January 12, 2012, two individuals each filed a notice of appeal and a request for evidentiary hearing with the MDEQ regarding the surface coal mining and water pollution control permits. On March 8, 2012, the MDEQ permit board affirmed its issuance of the surface coal mining and water pollution control permits.

In 2009, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $133 million of Internal Revenue Code Section 48A tax credits (Phase I) to Mississippi Power. On April 19, 2011, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to Mississippi Power. The utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the recapture rules for Section 48A investment tax credits. Through March 31, 2012, Mississippi Power received or accrued tax benefits totaling $141.1 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

taxable income, Mississippi Power estimates that it will not be able to utilize $105.0 million of these tax credits until after 2012. IRS guidelines allow the resulting unused credits to be carried forward for 20 years.

In July 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In December 2010, Mississippi Power and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval of SMEPA's 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the joint petition for the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power's senior unsecured credit rating falls below a BBB+ and/or Baa1. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the deposit has been presented as a current liability in Mississippi Power's Condensed Balance Sheet herein and as financing proceeds in the statement of cash flows.

As of March 31, 2012, Mississippi Power had spent a total of $1.30 billion on the Kemper IGCC including the cost of the lignite mine and equipment, the CO_2 pipeline facilities, and regulatory filing costs. Of this total, $1.28 billion was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $22.9 million was recorded in other regulatory assets, $2.3 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed.

See Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters — Certificated New Plant" in Item 8 of the Form 10-K for information on the proposed rate schedules related to the Kemper IGCC.

The ultimate outcome of these matters cannot be determined at this time.

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NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

(C) FAIR VALUE MEASUREMENTS

As of March 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

As of March 31, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Southern Company				
Assets:				
Energy-related derivatives	$ —	$ 24	$—	$ 24
Interest rate derivatives	—	14	—	14
Foreign currency derivatives	—	1	—	1
Nuclear decommissioning trusts [(a)]	490	788	—	1,278
Cash equivalents and restricted cash	862	—	—	862
Other investments	4	50	15	69
Total	$1,356	$877	$15	$2,248
Liabilities:				
Energy-related derivatives	$ —	$289	$—	$ 289
Interest rate derivatives	—	10	—	10
Foreign currency derivatives	—	1	—	1
Total	$ —	$300	$—	$ 300
Alabama Power				
Assets:				
Energy-related derivatives	$ —	$ 1	$—	$ 1
Nuclear decommissioning trusts: [(b)]				
Domestic equity	283	63	—	346
Foreign equity [(d)]	27	56	—	83
U.S. Treasury and government agency securities	15	8	—	23
Corporate bonds	—	99	—	99
Mortgage and asset backed securities	—	26	—	26
Other	—	10	—	10
Cash equivalents and restricted cash	234	—	—	234
Total	$ 559	$263	$—	$ 822
Liabilities:				
Energy-related derivatives	$ —	$ 54	$—	$ 54
Interest rate derivatives	—	10	—	10
Total	$ —	$ 64	$—	$ 64

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NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

As of March 31, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Georgia Power				
Assets:				
Energy-related derivatives	$ —	$ 22	$ —	$ 22
Nuclear decommissioning trusts: [c]				
Domestic equity	165	1	—	166
Foreign equity [d]	—	109	—	109
U.S. Treasury and government agency securities	—	52	—	52
Municipal bonds	—	83	—	83
Corporate bonds	—	123	—	123
Mortgage and asset backed securities	—	127	—	127
Other	—	31	—	31
Total	$165	$548	$ —	$713
Liabilities:				
Energy-related derivatives	$ —	$108	$ —	$108
Gulf Power				
Assets:				
Cash equivalents	$ 15	$ —	$ —	$ 15
Liabilities:				
Energy-related derivatives	$ —	$ 54	$ —	$ 54
Mississippi Power				
Assets:				
Foreign currency derivatives	$ —	$ 1	$ —	$ 1
Cash equivalents	439	—	—	439
Total	$439	$ 1	$ —	$440
Liabilities:				
Energy-related derivatives	$ —	$ 56	$ —	$ 56
Foreign currency derivatives	—	1	—	1
Total	$ —	$ 57	$ —	$ 57
Southern Power				
Assets:				
Energy-related derivatives	$ —	$ 1	$ —	$ 1
Liabilities:				
Energy-related derivatives	$ —	$ 17	$ —	$ 17

(a) For additional detail, see the nuclear decommissioning trusts sections for Alabama Power and Georgia Power in this table.
(b) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.
(c) Includes the investment securities pledged to creditors and cash collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the securities lending program. As of March 31, 2012, approximately $41 million of the fair market value of Georgia Power's nuclear decommissioning trust funds' securities were on loan and pledged to creditors under the funds' managers' securities lending program.
(d) Level 1 securities consist of actively traded stocks, while Level 2 securities consist of pooled funds.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and LIBOR interest rates. Interest rate and foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. Inputs for foreign currency derivatives are from observable market sources. See Note (H) herein for additional information on how these derivatives are used.

“Other investments” include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.

For fair value measurements of investments within the nuclear decommissioning trusts and rabbi trust funds, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts and rabbi trust funds with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then used in the valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts’ judgment are also obtained when available.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

As of March 31, 2012, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

As of March 31, 2012:	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
		(in millions)		
Southern Company				
Nuclear decommissioning trusts:				
Corporate bonds — commingled funds	$ 12	None	Daily	1 to 3 days
Other — commingled funds	87	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	93	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	862	None	Daily	Not applicable
Alabama Power				
Nuclear decommissioning trusts:				
Other — commingled funds	56	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	93	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	234	None	Daily	Not applicable
Georgia Power				
Nuclear decommissioning trusts:				
Corporate bonds — commingled funds	12	None	Daily	1 to 3 days
Other — commingled funds	31	None	Daily	Not applicable
Gulf Power				
Cash equivalents:				
Money market funds	15	None	Daily	Not applicable
Mississippi Power				
Cash equivalents:				
Money market funds	439	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (the Funds) to comply with the NRC's regulations. The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high grade money market instruments, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations having a maximum five-year final maturity with put features or floating rates with a reset date of 13 months or less. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The corporate bonds — commingled funds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 to the financial statements of Southern Company and Georgia Power under "Nuclear Decommissioning" in Item 8 of the Form 10-K for additional information.

Alabama Power's nuclear decommissioning trust includes investments in Trust-Owned Life Insurance (TOLI). The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities,

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

Southern Company, Alabama Power, and Georgia Power continue to elect the option to fair value investment securities held in the nuclear decommissioning trust funds. For the three months ended March 31, 2012, the increase in fair value of the funds, which includes reinvested interest and dividends, is recorded in the regulatory liability and was $86 million for Southern Company, $49 million for Alabama Power, and $37 million for Georgia Power.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the investment in the money market funds.

At March 31, 2012, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
Southern Company	$20,843	$25,499
Alabama Power	$ 6,380	$ 7,789
Georgia Power	$ 8,918	$11,837
Gulf Power	$ 1,236	$ 1,349
Mississippi Power	$ 1,668	$ 1,740
Southern Power	$ 1,303	$ 1,393

The fair values were Level 2 and are based on quoted market prices for the same or similar issues or on the current rates offered to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power.

(D) STOCKHOLDERS' EQUITY

Earnings per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. See Note 8 to the financial statements of Southern Company in Item 8 of the Form 10-K for information on the stock option and performance share plans. The effects of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(in millions)	
As reported shares	**868**	848
Effect of options and performance share award units	**9**	6
Diluted shares	**877**	854

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were 1 million and 7 million for the three months ended March 31, 2012 and 2011, respectively.

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NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

Changes in Stockholders' Equity

The following table presents year-to-date changes in stockholders' equity of Southern Company:

	Number of Common Shares Issued	Number of Common Shares Treasury	Common Stockholders' Equity	Preferred and Preference Stock of Subsidiaries	Total Stockholders' Equity
	(in thousands)			*(in millions)*	
Balance at December 31, 2011	865,664	(539)	$17,578	$707	$18,285
Net income after dividends on preferred and preference stock	—	—	368	—	368
Other comprehensive income (loss)	—	—	6	—	6
Stock issued	3,571	—	157	—	157
Cash dividends on common stock	—	—	(410)	—	(410)
Other	—	(6)	—	—	—
Balance at March 31, 2012	869,235	(545)	$17,699	$707	$18,406
Balance at December 31, 2010	843,814	(474)	$16,202	$707	$16,909
Net income after dividends on preferred and preference stock	—	—	422	—	422
Other comprehensive income (loss)	—	—	4	—	4
Stock issued	5,784	—	222	—	222
Cash dividends on common stock	—	—	(385)	—	(385)
Other	—	(1)	—	—	—
Balance at March 31, 2011	849,598	(475)	$16,465	$707	$17,172

(E) FINANCING

Bank Credit Arrangements

Bank credit arrangements provide liquidity support to the registrants' commercial paper borrowings and the traditional operating companies' variable rate pollution control revenue bonds. See Note 6 to the financial statements of each registrant under "Bank Credit Arrangements" in Item 8 of the Form 10-K for additional information.

The following table outlines the credit arrangements by company as of March 31, 2012:

Company	Expires 2012	Expires 2013	Expires 2014 and Beyond	Total	Unused	Executable Term Loans One Year	Executable Term Loans Two Years	Due Within One Year (a) Term Out	Due Within One Year (a) No Term Out
		(in millions)		*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ —	$ —	$1,000	$1,000	$1,000	$ —	$—	$ —	$ —
Alabama Power	121	35	1,150	1,306	1,306	51	—	51	71
Georgia Power	—	—	1,750	1,750	1,745	—	—	—	—
Gulf Power	75	35	165	275	275	75	—	75	35
Mississippi Power	106	25	165	296	296	25	41	66	65
Southern Power	—	—	500	500	500	—	—	—	—
Other	25	25	—	50	50	25	—	25	—
Total	$327	$120	$4,730	$5,177	$5,172	$176	$41	$217	$171

(a) Reflects facilities expiring on or before March 31, 2013.

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NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

(F) RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions.

See Note 2 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power in Item 8 of the Form 10-K for additional information.

Components of the net periodic benefit costs for the three months ended March 31, 2012 and 2011 were as follows:

Pension Plans	**Southern Company**	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**
			(in millions)		
Three Months Ended March 31, 2012					
Service cost	$ 50	$ 11	$ 15	$ 2	$ 2
Interest cost	98	23	35	4	5
Expected return on plan assets	(145)	(40)	(55)	(6)	(6)
Net amortization	31	8	11	1	1
Net cost (income)	$ 34	$ 2	$ 6	$ 1	$ 2
Three Months Ended March 31, 2011					
Service cost	$ 46	$ 11	$ 14	$ 2	$ 2
Interest cost	98	24	36	4	4
Expected return on plan assets	(152)	(43)	(59)	(7)	(6)
Net amortization	13	3	5	1	1
Net cost (income)	$ 5	$ (5)	$ (4)	$—	$ 1

Postretirement Benefits	**Southern Company**	**Alabama Power**	**Georgia Power**	**Gulf Power**	**Mississippi Power**
			(in millions)		
Three Months Ended March 31, 2012					
Service cost	$ 5	$ 1	$ 1	$—	$—
Interest cost	21	5	9	1	1
Expected return on plan assets	(15)	(6)	(7)	—	—
Net amortization	5	2	3	—	—
Net cost (income)	$ 16	$ 2	$ 6	$ 1	$ 1
Three Months Ended March 31, 2011					
Service cost	$ 5	$ 1	$ 2	$—	$—
Interest cost	23	6	10	1	1
Expected return on plan assets	(16)	(6)	(8)	—	—
Net amortization	5	2	3	—	—
Net cost (income)	$ 17	$ 3	$ 7	$1	$ 1

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

(G) EFFECTIVE TAX RATE AND UNRECOGNIZED TAX BENEFITS

Effective Tax Rate

See Note 5 to the financial statements of each registrant in Item 8 of the Form 10-K for information on the effective income tax rate.

Southern Company

Southern Company's effective tax rate was 34.2% for the three months ended March 31, 2012 compared to 34.6% for the corresponding period in 2011. Southern Company's effective tax rate is lower than the statutory rate primarily due to its employee stock plans' dividend deduction and non-taxable AFUDC equity.

Alabama Power

Alabama Power's effective tax rate was 38.3% for the three months ended March 31, 2012 compared to 37.1 % for the corresponding period in 2011. The increase was due to an increase in Alabama state income taxes as a result of a decrease in the state income tax deduction for federal income taxes paid.

Georgia Power

Georgia Power's effective tax rate was 34.9% for the three months ended March 31, 2012 compared to 34.6% for the corresponding period in 2011. The increase was primarily due to a decrease in AFUDC equity, which is non-taxable.

Gulf Power

Gulf Power's effective tax rate was 34.6% for the three months ended March 31, 2012 compared to 33.8% for the corresponding period in 2011. The increase was primarily due to a decrease in AFUDC equity, which is non-taxable.

Mississippi Power

Mississippi Power's effective tax rate was 24.7% for the three months ended March 31, 2012 compared to 32.2% for the corresponding period in 2011. The decrease was primarily due to an increase in AFUDC equity, which is non-taxable, related to the Kemper IGCC.

Southern Power

Southern Power's effective tax rate was 31.3% for the three months ended March 31, 2012 compared to 35.6% for the corresponding period in 2011. The decrease was primarily due to lower earnings before income taxes and a settlement with the IRS related to the production activities deduction. See "Unrecognized Tax Benefits" herein for additional information.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

Unrecognized Tax Benefits

Changes during 2012 for unrecognized tax benefits were as follows:

	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
	(in millions)					
Unrecognized tax benefits as of December 31, 2011	$ 120	$ 32	$ 47	$ 3	$ 5	$ 3
Tax positions from current periods	3	1	1	—	—	—
Tax positions from prior periods	(6)	(3)	(1)	—	(1)	(2)
Reductions due to settlements	(5)	(2)	(3)	(1)	—	1
Reductions due to expired statute of limitations	—	—	—	—	—	—
Balance as of March 31, 2012	$ 112	$ 28	$ 44	$ 2	$ 4	$ 2

The tax positions from current periods relate primarily to state investment tax credits and the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The decreases in tax positions from prior periods and reductions due to settlements relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

The impact on the effective tax rate, if recognized, was as follows:

	As of March 31, 2012			As of December 31, 2011
	Georgia Power	Other Registrants	Southern Company	Southern Company
	(in millions)			
Tax positions impacting the effective tax rate	**$24**	**$ 5**	**$ 59**	$ 69
Tax positions not impacting the effective tax rate	**20**	**32**	**53**	51
Balance of unrecognized tax benefits	**$44**	**$37**	**$112**	$120

The tax positions impacting the effective tax rate primarily relate to state investment tax credits and a litigation settlement refund claim for Southern Company. See Note 5 to the financial statements of Southern Company under "Effective Tax Rate" in Item 8 of the Form 10-K for additional information. The tax positions not impacting the effective tax rate relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	Georgia Power	Other Registrants	Southern Company
	(in millions)		
Interest accrued as of December 31, 2011	$ 6	$ 3	$ 10
Interest reclassified due to settlements	(2)	(3)	(5)
Interest accrued during the period	1	—	1
Balance as of March 31, 2012	$ 5	$ —	$ 6

All of the registrants classify interest on tax uncertainties as interest expense. The interest reclassified due to settlements is primarily associated with a settlement with the IRS related to the calculation methodology for the production activities deduction.

None of the registrants accrued any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of the registrants' unrecognized tax positions will significantly increase or decrease within the next 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of federal and state audits, could also impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change for repair costs associated with its subsidiaries' generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. On August 19, 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. The utility industry anticipates more detailed guidance concerning these regulations. Due to uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time.

(H) DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities.

Energy-Related Derivatives

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. Southern Power has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.

- *Cash Flow Hedges* — Gains and losses on energy-related derivatives designated as cash flow hedges, which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions, are reflected in earnings.

- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At March 31, 2012, the net volume of energy-related derivative contracts for power and natural gas positions for the Southern Company system, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Power			**Gas**		
	Net (Sold) MWHs	**Longest Hedge Date**	**Longest Non-Hedge Date**	**Net Purchased mmBtu**	**Longest Hedge Date**	**Longest Non-Hedge Date**
	(in millions)			*(in millions)*		
Southern Company	(0.1)	—	2012	221	2017	2017
Alabama Power	—	—	—	37	2017	—
Georgia Power	—	—	—	85	2017	—
Gulf Power	—	—	—	43	2017	—
Mississippi Power	—	—	—	28	2017	—
Southern Power	(0.1)	—	2012	28	2012	2017

In addition to the volumes discussed in the above table, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 9 million mmBtu for Southern Company, 4 million mmBtu for Georgia Power, 2 million mmBtu for Southern Power, and is immaterial for the other registrants.

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending March 31, 2013 are immaterial for all registrants.

Interest Rate Derivatives

Southern Company and certain subsidiaries also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset with any difference representing ineffectiveness.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

At March 31, 2012, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) March 31, 2012
	(in millions)				*(in millions)*
Cash flow hedges of forecasted transactions					
Alabama Power	$300	3-month LIBOR	2.90%*	December 2022	$(10)
Fair value hedges of existing debt					
Southern Company	350	4.15%	3-month LIBOR + 1.96%*	May 2014	14
Total	$650				$ 4

* Weighted Average

The following table reflects the estimated pre-tax gains (losses) that will be reclassified from OCI to interest expense for the next 12-month period ending March 31, 2013, together with the longest date that total deferred gains and losses are expected to be amortized into earnings.

Registrant	Estimated Gain (Loss) to be Reclassified for the 12 Months Ending March 31, 2013	Total Deferred Gains (Losses) Amortized Through
	(in millions)	
Southern Company	$(16)	2037
Alabama Power	1	2035
Georgia Power	(3)	2037
Gulf Power	(1)	2020
Mississippi Power	(1)	2022
Southern Power	(11)	2016

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as fair value hedges where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is typically recorded directly to earnings; however, Mississippi Power has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

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NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

At March 31, 2012, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) March 31, 2012
	(in millions)			*(in millions)*
Fair value hedges of firm commitments				
Mississippi Power	EUR6.8	1.3805 Dollars per Euro*	Various through March 2014	$—
Derivatives not designated as hedges				
Mississippi Power	EUR18.1	1.3209 Dollars per Euro*	N/A	—
Total	EUR24.9			$—

* Weighted Average

Derivative Financial Statement Presentation and Amounts

At March 31, 2012, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

Asset Derivatives at March 31, 2012						
	Fair Value					
Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
	(in millions)					
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Other current assets	$17	$—	$17	$—	$—	
Other deferred charges and assets	6	1	5	—	—	
Total derivatives designated as hedging instruments for regulatory purposes	$23	$ 1	$22	$—	$—	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:						
Other current assets	$ 6	$—	$—	$—	$—	$—
Other deferred charges and assets	8	—	—	—	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$14	$—	$—	$—	$—	$—
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Other deferred charges and assets	$ 1	$—	$—	$—	$—	$ 1
Foreign currency derivatives						
Other current assets	1	—	—	—	1	—

Total derivatives not designated as hedging instruments	$ 2	$—	$—	$—	$ 1	$ 1
Total asset derivatives	$39	$ 1	$22	$—	$ 1	$ 1

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Liability Derivatives at March 31, 2012

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
	Fair Value					
	(in millions)					
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:						
Liabilities from risk management activities	$191	$41	$ 80	$31	$39	
Other deferred credits and liabilities	81	13	28	23	17	
Total derivatives designated as hedging instruments for regulatory purposes	$272	$54	$108	$54	$56	N/A
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:						
Liabilities from risk management activities	$ 2	$—	$ —	$—	$—	$ 2
Interest rate derivatives:						
Liabilities from risk management activities	10	10	—	—	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	$ 12	$10	$ —	$—	$—	$ 2
Derivatives not designated as hedging instruments						
Energy-related derivatives:						
Liabilities from risk management activities	$ 15	$—	$ —	$—	$—	$ 15
Foreign currency derivatives:						
Liabilities from risk management activities	1	—	—	—	1	—
Total derivatives not designated as hedging instruments	$ 16	$—	$ —	$—	$ 1	$ 15
Total liability derivatives	$300	$64	$108	$54	$57	$ 17

All derivative instruments are measured at fair value. See Note (C) herein for additional information.

At March 31, 2012, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

Regulatory Hedge Unrealized Gain (Loss) Recognized on the Balance Sheet

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
	(in millions)				
Energy-related derivatives:					
Other regulatory assets, current	$(191)	$(41)	$(80)	$(31)	$(39)
Other regulatory assets, deferred	(81)	(13)	(28)	(23)	(17)
Other regulatory liabilities, current	17	—	17	—	—
Other regulatory liabilities, deferred	6	1	—	—	—
Other deferred credits and liabilities*	—	—	5	—	—
Total energy-related derivative gains (losses)	$(249)	$(53)	$(86)	$(54)	$(56)

* Georgia Power includes Other regulatory liabilities, deferred in Other deferred credits and liabilities.

For the three months ended March 31, 2012 and March 31, 2011, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on Southern Company’s statements of income were immaterial.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

For the three months ended March 31, 2012, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on Southern Company's and Mississippi Power's statements of income were immaterial. For the three months ended March 31, 2011, the pre-tax gains from foreign currency derivatives designated as fair value hedging instruments on Southern Company's and Mississippi Power's statements of income were $3 million. This amount was offset with changes in the fair value of the purchase commitment related to equipment purchases; therefore, there was no impact on Southern Company's or Mississippi Power's statements of income.

For the three months ended March 31, 2012 and March 31, 2011, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)		Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		
			Statements of Income Location	Amount	
	2012	2011		**2012**	2011
	(in millions)			*(in millions)*	
Southern Company					
Energy-related derivatives	**$ (1)**	$ 1	Fuel	**$ —**	$ —
Interest rate derivatives	**6**	4	Interest expense, net of amounts capitalized	**(3)**	(5)
Total	**$ 5**	$ 5		**$ (3)**	$ (5)
Alabama Power					
Interest rate derivatives	**$ 7**	$ 4	Interest expense, net of amounts capitalized	**$ —**	$ —
Georgia Power					
Interest rate derivatives	**$ —**	$ —	Interest expense, net of amounts capitalized	**$ (1)**	$ (1)
Gulf Power					
Interest rate derivatives	**$ —**	$ —	Interest expense, net of amounts capitalized	**$ —**	$ —
Mississippi Power					
Interest rate derivatives	**$ (1)**	$ —	Interest expense, net of amounts capitalized	**$ —**	$ —
Southern Power					
Energy-related derivatives	**$ (1)**	$ 1	Fuel	**$ —**	$ —
Interest rate derivatives	**—**	—	Interest expense, net of amounts capitalized	**(2)**	(3)
Total	**$ (1)**	$ 1		**$ (2)**	$ (3)

There was no material ineffectiveness recorded in earnings for any registrant for any period presented.

For the three months ended March 31, 2012, the pre-tax losses from energy-related derivatives not designated as hedging instruments on the statements of income were $6 million for Southern Company and Southern Power. For the three months ended March 31, 2011, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income were immaterial for Southern Company and Southern Power.

For the three months ended March 31, 2012, the pre-tax effects of foreign currency derivatives not designated as hedging instruments were recorded as regulatory assets and liabilities and were immaterial for Southern Company and Mississippi Power.

Contingent Features

The registrants do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At March 31, 2012, the fair value of derivative liabilities with contingent features, by registrant, was as follows:

	Southern Company	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
			(in millions)			
Derivative liabilities	$36	$9	$10	$7	$6	$4

At March 31, 2012, the registrants had no collateral posted with their derivative counterparties. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $36 million for each registrant. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. For the traditional operating companies and Southern Power, included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participant has a credit rating change to below investment grade.

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NOTES TO THE CONDENSED FINANCIAL STATEMENTS: (Continued)

(I) SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Southern Power's revenues from sales to the traditional operating companies were $112 million and $83 million for the three months ended March 31, 2012 and March 31, 2011, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other intersegment revenues are not material. Financial data for business segments and products and services was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
Three Months Ended March 31, 2012:							
Operating revenues	$ 3,449	$ 254	$ (114)	$ 3,589	$ 38	$ (23)	$ 3,604
Segment net income *	339	29	1	369	2	(3)	368
Total assets at March 31, 2012	$55,698	$3,596	$ (81)	$59,213	$1,086	$(425)	$59,874
Three Months Ended March 31, 2011:							
Operating revenues	$ 3,810	$ 282	$ (98)	$ 3,994	$ 38	$ (20)	$ 4,012
Segment net income (loss)*	385	38	—	423	1	(2)	422
Total assets at December 31, 2011	$54,622	$3,581	$ (127)	$58,076	$1,592	$(401)	$59,267

* After dividends on preferred and preference stock of subsidiaries

Products and Services

	Electric Utilities' Revenues			
Period	Retail	Wholesale	Other	Total
		(in millions)		
Three Months Ended March 31, 2012	$3,092	$349	$148	$3,589
Three Months Ended March 31, 2011	$3,396	$449	$149	$3,994

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PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

See the Notes to the Condensed Financial Statements herein for information regarding certain legal and administrative proceedings in which the registrants are involved.

Item 1A. Risk Factors.

See RISK FACTORS in Item 1A of the Form 10-K for a discussion of the risk factors of the registrants. There have been no material changes to these risk factors from those previously disclosed in the Form 10-K.

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Item 6. Exhibits.

(4) Instruments Describing Rights of Security Holders, Including Indentures

Georgia Power

(c)1	-	Forty-Sixth Supplemental Indenture to Senior Note Indenture dated as of March 6, 2012, providing for the issuance of the Series 2012A 4.30% Senior Notes due March 15, 2042. (Designated in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2.)

Mississippi Power

(e)1	-	Thirteenth Supplemental Indenture to Senior Note Indenture dated as of March 9, 2012, providing for the issuance of the Series 2012A 4.25% Senior Notes due March 15, 2042. (Designated in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b).)

(10) Material Contracts

Southern Company

(a)1	-	Base Salaries of Named Executive Officers.

Alabama Power

(b)1	-	Base Salaries of Named Executive Officers.

Georgia Power

(c)1	-	Base Salaries of Named Executive Officers.
(c)2	-	Amendment No. 5, dated as of February 7, 2012, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Georgia Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power has omitted such portions from the filing and filed them separately with the SEC.)

Mississippi Power

(e)1	-	Base Salaries of Named Executive Officers.

(24) Power of Attorney and Resolutions

Southern Company

(a)1	-	Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2011, File No. 1-3526 as Exhibit 24(a) and incorporated herein by reference.)

Alabama Power

(b)1	-	Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2011, File No. 1-3164 as Exhibit 24(b) and incorporated herein by reference.)

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Georgia Power

(c)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2011, File No. 1-6468 as Exhibit 24(c) and incorporated herein by reference.)

Gulf Power

(d)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2011, File No. 001-31737 as Exhibit 24(d) and incorporated herein by reference.)

Mississippi Power

(e)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2011, File No. 001-11229 as Exhibit 24(e) and incorporated herein by reference.)

Southern Power

(f)1 - Power of Attorney and resolution. (Designated in the Form 10-K for the year ended December 31, 2011, File No. 333-98553 as Exhibit 24(f) and incorporated herein by reference.)

(31) Section 302 Certifications

Southern Company

(a)1 - Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(a)2 - Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

(b)1 - Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(b)2 - Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

(c)1 - Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(c)2 - Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

(d)1 - Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(d)2 - Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

(e)1	-	Certificate of Mississippi Power’s Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
(e)2	-	Certificate of Mississippi Power’s Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

(f)1	-	Certificate of Southern Power’s Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
(f)2	-	Certificate of Southern Power’s Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

(a)	-	Certificate of Southern Company’s Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

(b)	-	Certificate of Alabama Power’s Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

(c)	-	Certificate of Georgia Power’s Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

(d)	-	Certificate of Gulf Power’s Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

(e)	-	Certificate of Mississippi Power’s Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

(f)	-	Certificate of Southern Power’s Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

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(101)	**XBRL — Related Documents**
INS	XBRL Instance Document
SCH	XBRL Taxonomy Extension Schema Document
CAL	XBRL Taxonomy Calculation Linkbase Document
DEF	XBRL Definition Linkbase Document
LAB	XBRL Taxonomy Label Linkbase Document
PRE	XBRL Taxonomy Presentation Linkbase Document

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

THE SOUTHERN COMPANY

By *Thomas A. Fanning*
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

By *Art P. Beattie*
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 7, 2012

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ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

ALABAMA POWER COMPANY

By *Charles D. McCrary*
President and Chief Executive Officer
(Principal Executive Officer)

By *Philip C. Raymond*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 7, 2012

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GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

GEORGIA POWER COMPANY

By *W. Paul Bowers*
President and Chief Executive Officer
(Principal Executive Officer)

By *Ronnie R. Labrato*
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 7, 2012

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

GULF POWER COMPANY

By *Mark A. Crosswhite*
President and Chief Executive Officer
(Principal Executive Officer)

By *Richard S. Teel*
Vice President and Chief Financial Officer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 7, 2012

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

MISSISSIPPI POWER COMPANY

By *Edward Day, VI*
President and Chief Executive Officer
(Principal Executive Officer)

By *Moses H. Feagin*
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 7, 2012

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof included in such company's report.

SOUTHERN POWER COMPANY

By *Oscar C. Harper, IV*
President and Chief Executive Officer
(Principal Executive Officer)

By *Michael W. Southern*
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

By */s/ Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: May 7, 2012

Exhibit 10(a)1

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

THE SOUTHERN COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of The Southern Company (the "Company") and certain other executive officers of the Company who served during 2011.

Thomas A. Fanning Chairman, President and Chief Executive Officer	$1,125,000
Art P. Beattie Executive Vice President and Chief Financial Officer	$628,732
W. Paul Bowers Executive Vice President of the Company, President and Chief Executive Officer of Georgia Power Company	$743,585
Charles D. McCrary Executive Vice President of the Company, President and Chief Executive Officer of Alabama Power Company	$781,369
Anthony J. Topazi Executive Vice President and Chief Operating Officer	$646,089

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

ALABAMA POWER COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of Alabama Power Company and certain other executive officers of Alabama Power Company who served during 2011.

Charles D. McCrary President and Chief Executive Officer	$781,369
Philip C. Raymond Executive Vice President, Chief Financial Officer, and Treasurer	$284,591
Theodore J. McCullough Senior Vice President	$225,884
Zeke W. Smith Executive Vice President	$283,541
Steven R. Spencer Executive Vice President	$428,784

EXHIBIT 10(c)1

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

GEORGIA POWER COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of Georgia Power Company and certain other executive officers of Georgia Power Company who served during 2011.

W. Paul Bowers President and Chief Executive Officer	$743,585
Ronnie R. Labrato Executive Vice President, Chief Financial Officer and Treasurer	$302,575
W. Craig Barrs Executive Vice President	$312,000
Mickey A. Brown* Executive Vice President	$383,877
Joseph A. Miller Executive Vice President	$403,065

*Retired February 1, 2012

Exhibit 10(c)(2)

Georgia Power Company has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the Securities and Exchange Commission. Georgia Power Company has omitted such portions from this filing and filed them separately with the Securities and Exchange Commission. Such omissions are designated as "[***]."

AMENDMENT NO. 5

TO

ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT

BETWEEN

GEORGIA POWER COMPANY, FOR ITSELF AND AS AGENT FOR OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA AND THE CITY OF DALTON, GEORGIA, ACTING BY AND THROUGH ITS BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS, AS OWNERS

AND

A CONSORTIUM CONSISTING OF WESTINGHOUSE ELECTRIC COMPANY LLC AND STONE & WEBSTER, INC., AS CONTRACTOR

FOR UNITS 3 & 4 AT THE VOGTLE ELECTRIC GENERATING PLANT SITE

IN WAYNESBORO, GEORGIA

DATED AS OF APRIL 8, 2008

AMENDMENT NO. 5 TO

ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT

This AMENDMENT NO. 5 (the "Amendment") TO THE ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT, dated April 8, 2008, as amended (the "Agreement") by and between GEORGIA POWER COMPANY, a Georgia corporation ("GPC"), acting for itself and as agent for OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), an electric membership corporation formed under the laws of the State of Georgia, MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, a public body corporate and politic and an instrumentality of the State of Georgia, and THE CITY OF DALTON, GEORGIA, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners (hereinafter referred to collectively as "Owners") , and a consortium consisting of WESTINGHOUSE ELECTRIC COMPANY LLC, a Delaware limited liability company having a place of business in Cranberry Township, Pennsylvania ("Westinghouse"), and STONE & WEBSTER, INC. a Louisiana corporation having a place of business in Charlotte, North Carolina ("Stone & Webster") (hereinafter referred to collectively as "Contractor"), is entered into as of the 7th day of February 2012.

RECITALS

WHEREAS, Owners and Contractor entered into the Agreement, as of April 8, 2008, to provide for, among other things, the design, engineering, procurement, installation, construction and technical support of start-up and testing of equipment, materials and structures comprising the Facility;

WHEREAS, the Parties have entered into four (4) prior amendments to the Agreement and, have agreed that it would be beneficial to amend the Agreement a fifth time to memorialize a recent agreement between them regarding access to certain Westinghouse information

WHEREAS, the Parties' recent agreement and this revision will not affect the Project Schedule or the Contract Price; and

WHEREAS, the Parties agree that, with the exception of the changes expressly stated herein, this Amendment will not change the terms and conditions of the Agreement.

NOW, THEREFORE, in consideration of the recitals, the mutual promises herein and other good and valuable consideration, the receipt and sufficiency of which the Parties acknowledge, the Parties, intending to be legally bound, stipulate and agree as follows:

1. Contractor hereby agrees and represents that this Amendment shall not cause, directly or indirectly, any delay in the Project Schedule or any increase in the Contract Price.

2. Article 1 Definitions. Article 1 is hereby amended to add the definition of "Westinghouse Accessible Information" as follows:

"'Westinghouse Accessible Information' has the meaning set forth in Section 19.3(h)."

3. Article 19 Confidential and Proprietary Information, Section 19.3 – Special Procedures Pertaining to Contractor's Confidential and Proprietary Information. Section 19.3 is hereby amended by adding the following new subsection (h):

"(h) Westinghouse Accessible Information. Westinghouse Accessible Information shall consist of the Westinghouse information and Westinghouse documents referenced or cited in the current revision of the AP1000 design certification document and required to be incorporated into or referenced in the COLA that are not otherwise Documentation deliverable to Owners under this Agreement. Owners, Southern Nuclear and the NRC will have the right to access and review Westinghouse Accessible Information at any of Westinghouse's offices at reasonable times and subject to reasonable requirements of Westinghouse. Neither Southern Nuclear nor any Owner shall have the right to copy or remove Westinghouse Accessible Information from Westinghouse's facility. Owners and Southern Nuclear agree not to use Westinghouse Accessible Information unless such use is solely for Facility Purposes. Owners and Southern Nuclear shall maintain Westinghouse Accessible Information in confidence and shall not disclose it to any Third Party without Westinghouse's prior written approval. Owners or Southern Nuclear may disclose Westinghouse Accessible Information to the NRC, but only after Owners provide Contractor with prior written notice of any such proposed disclosure. Any disclosure to the NRC shall be made on a confidential basis and Owner shall advise the NRC that the information being disclosed is proprietary to Westinghouse at the time of the disclosure. All requests for access to Westinghouse Accessible Information will be handled on a case-by-case basis. Any and all effort incurred by Westinghouse, including but not limited to making the necessary arrangements for access, time spent in preparing for such access, and review of notes prior to exit from Westinghouse's facility, [***]. Any work required of Westinghouse in support of Owners' access and review of Westinghouse Accessible Information, including, but not limited to, analyses, manipulation of data, and running of computer models, [***]. The terms of this Section 19.3(h) are self-contained and are not altered by other provisions of this Article 19."

Miscellaneous

4.1 Capitalized terms used herein and not defined herein have the meanings assigned in the Agreement.

4.2 This Amendment No. 5 shall be construed in connection with and as part of the Agreement, and all terms, conditions, and covenants contained in the Agreement, except as herein modified, shall be and shall remain in full force and effect. The Parties hereto agree that they are bound by the terms, conditions and covenants of the Agreement as amended hereby.

4.3 The validity, interpretation, and performance of this Amendment and each of its provisions shall be governed by the laws of the State of Georgia, without giving effect to the principles thereof relating to conflicts of laws.

4.4 Except as expressly provided for in this Amendment No. 5, a ll other Articles, Sections and Exhibits of and to the Agreement and guarantees associated with this Agreement remain unchanged.

4.5 This Amendment may be executed simultaneously in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

IN WITNESS WHEREOF, the Parties have duly executed this Amendment No. 5 as of the date first above written.

WESTINGHOUSE ELECTRIC COMPANY LLC

By: /s/ Thomas H. Dent ________
Name: Thomas H. Dent
Title: VP & Consortium Director

Attest: /s/ Rolf F. Ziesing _______
Its: OPS Director
(CORPORATE SEAL)

STONE & WEBSTER, INC .

By: /s/ R.M. Glover ___________
Name: R.M. Glover
Title: Authorized Representative

Attest: /s/ T. Jason Dunaway ____
Its: Director/ Business Manager
(CORPORATE SEAL)

GEORGIA POWER COMPANY, as an Owner and as agent for the other Owners

By: /s/ Joseph A. Miller ________
Name: Joseph A. Miller
Title: Executive VP

Attest: /s/ Thomas P. Bishop _____
Its: SVP & Corporate Secretary
(CORPORATE SEAL)

EXHIBIT 10(e)1

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

MISSISSIPPI POWER COMPANY

The following are the annual base salaries, effective March 1, 2012, of the Chief Executive Officer and Chief Financial Officer of Mississippi Power Company and certain other executive officers of Mississippi Power Company who served during 2011.

Edward Day, VI President and Chief Executive Officer	$407,056
Moses H. Feagin Vice President, Treasurer and Chief Financial Officer	$234,073
Thomas O. Anderson, IV Vice President	$194,461
John W. Atherton Vice President	$234,073
Jeff G. Franklin Vice President	$237,652
Donald R. Horsley* Vice President	$300,706

*Served as an executive officer of Mississippi Power Company through July 31, 2011

Exhibit 31(a)1

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Thomas A. Fanning, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Southern Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Thomas A Fanning

Thomas A. Fanning

Chairman, President and Chief Executive Officer

Exhibit 31(a)2

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Art P. Beattie, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Southern Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Art P. Beattie
Art P. Beattie

Executive Vice President and Chief Financial Officer

Exhibit 31(b)1

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Charles D. McCrary, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Alabama Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Charles D. McCrary

Charles D. McCrary
President and Chief Executive Officer

Exhibit 31(b)2

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Philip C. Raymond, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Alabama Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Philip C. Raymond
Philip C. Raymond

Executive Vice President, Chief Financial Officer and Treasurer

Exhibit 31(c)1

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, W. Paul Bowers, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Georgia Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/W. Paul Bowers

W. Paul Bowers
President and Chief Executive Officer

Exhibit 31(c)2

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Ronnie R. Labrato, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Georgia Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Ronnie R. Labrato

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer and Treasurer

Exhibit 31(d)1

GULF POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Mark A. Crosswhite, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Gulf Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Mark A. Crosswhite
Mark A. Crosswhite

President and Chief Executive Officer

GULF POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Richard S. Teel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Gulf Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Richard S. Teel
Richard S. Teel

Vice President and Chief Financial Officer

Exhibit 31(e)1

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Edward Day, VI, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Mississippi Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Edward Day, VI

Edward Day, VI
President and Chief Executive Officer

Exhibit 31(e)2

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Moses H. Feagin, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Mississippi Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 7, 2012

/s/Moses H. Feagin

Moses H. Feagin
Vice President, Treasurer and Chief Financial Officer

Exhibit 31(f)1

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Oscar C. Harper IV, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Southern Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Oscar C. Harper IV
Oscar C. Harper IV

President and Chief Executive Officer

Exhibit 31(f)2

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Michael W. Southern, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Southern Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 7, 2012

/s/Michael W. Southern

Michael W. Southern

Senior Vice President, Treasurer and Chief Financial Officer

Exhibit 32(a)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of The Southern Company for the quarter ended March 31, 2012, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of The Southern Company for the quarter ended March 31, 2012, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of The Southern Company for the quarter ended March 31, 2012, fairly presents, in all material respects, the financial condition and results of operations of The Southern Company.

/s/Thomas A Fanning
Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Art P. Beattie
Art P. Beattie
Executive Vice President and
Chief Financial Officer

May 7, 2012

Exhibit 32(b)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Alabama Power Company for the quarter ended March 31, 2012, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Alabama Power Company for the quarter ended March 31, 2012, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Alabama Power Company for the quarter ended March 31, 2012, fairly presents, in all material respects, the financial condition and results of operations of Alabama Power Company.

/s/Charles D. McCrary
Charles D. McCrary
President and Chief Executive Officer

/s/Philip C. Raymond
Philip C. Raymond
Executive Vice President,
Chief Financial Officer and Treasurer

May 7, 2012

Exhibit 32(c)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Georgia Power Company for the quarter ended March 31, 2012, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Georgia Power Company for the quarter ended March 31, 2012, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Georgia Power Company for the quarter ended March 31, 2012, fairly presents, in all material respects, the financial condition and results of operations of Georgia Power Company.

/s/W. Paul Bowers
W. Paul Bowers
President and Chief Executive Officer

/s/Ronnie R. Labrato
Ronnie R. Labrato
Executive Vice President,
Chief Financial Officer and Treasurer

May 7, 2012

Exhibit 32(d)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Gulf Power Company for the quarter ended March 31, 2012, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Gulf Power Company for the quarter ended March 31, 2012, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Gulf Power Company for the quarter ended March 31, 2012, fairly presents, in all material respects, the financial condition and results of operations of Gulf Power Company.

/s/Mark A. Crosswhite
Mark A. Crosswhite
President and Chief Executive Officer

/s/Richard S. Teel
Richard S. Teel
Vice President and Chief Financial Officer

May 7, 2012

Exhibit 32(e)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Mississippi Power Company for the quarter ended March 31, 2012, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Mississippi Power Company for the quarter ended March 31, 2012, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Mississippi Power Company for the quarter ended March 31, 2012, fairly presents, in all material respects, the financial condition and results of operations of Mississippi Power Company.

/s/Edward Day, VI
Edward Day, VI
President and Chief Executive Officer

/s/Moses H. Feagin
Moses H. Feagin
Vice President, Treasurer and
Chief Financial Officer

May 7, 2012

Exhibit 32(f)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Quarterly Report on Form 10-Q of Southern Power Company for the quarter ended March 31, 2012, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Quarterly Report on Form 10-Q of Southern Power Company for the quarter ended March 31, 2012, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Quarterly Report on Form 10-Q of Southern Power Company for the quarter ended March 31, 2012, fairly presents, in all material respects, the financial condition and results of operations of Southern Power Company.

/s/Oscar C. Harper IV
Oscar C. Harper IV
President and Chief Executive Officer

/s/Michael W. Southern
Michael W. Southern
Senior Vice President, Treasurer and
Chief Financial Officer

May 7, 2012

VVC 10-Q 3/31/2012

Section 1: 10-Q (VVC 10Q)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2012

OR

[_] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________________ to ___________________

Commission file number: **1-15467**

VECTREN CORPORATION

(Exact name of registrant as specified in its charter)

[Missing Graphic Reference]

INDIANA	**35-2086905**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

One Vectren Square, Evansville, IN 47708
(Address of principal executive offices)
(Zip Code)

812-491-4000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
☐ Yes ☒ No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common Stock- Without Par Value	81,993,361	April 30, 2012
Class	Number of Shares	Date

Access to Information

Vectren Corporation makes available all SEC filings and recent annual reports free of charge through its website at www.vectren.com as soon as reasonably practicable after electronically filing or furnishing the reports to the SEC, or by request, directed to Investor Relations at the mailing address, phone number, or email address that follows:

Mailing Address:	Phone Number:	Investor Relations Contact:
One Vectren Square	(812) 491-4000	Robert L. Goocher
Evansville, Indiana 47708		Treasurer and Vice President, Investor Relations
		rgoocher@vectren.com

Definitions

BCF: billions of cubic feet

BTU: British thermal units

EPA: Environmental Protection Agency

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

IDEM: Indiana Department of Environmental Management

IURC: Indiana Utility Regulatory Commission

MISO: Midwest Independent System Operator

MSHA: Mine Safety and Health Administration

MW: megawatts

MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)

OUCC: Indiana Office of the Utility Consumer Counselor

PUCO: Public Utilities Commission of Ohio

Throughput: combined gas sales and gas transportation volumes

XBRL: eXtensible Business Reporting Language

Table of Contents

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited – In millions)

	March 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash & cash equivalents	$ 14.2	$ 8.6
Accounts receivable - less reserves of $6.1 & $6.7, respectively	214.6	221.3
Accrued unbilled revenues	67.8	121.5
Inventories	147.5	161.9
Recoverable fuel & natural gas costs	9.5	12.4
Prepayments & other current assets	41.6	84.3
Total current assets	**495.2**	**610.0**
Utility Plant		
Original cost	5,033.8	4,979.9
Less: accumulated depreciation & amortization	1,975.9	1,947.3
Net utility plant	**3,057.9**	**3,032.6**
Investments in unconsolidated affiliates	88.2	92.9
Other utility & corporate investments	35.5	34.4
Other nonutility investments	24.6	29.6
Nonutility plant - net	562.0	550.8
Goodwill - net	262.3	262.3
Regulatory assets	232.8	226.0
Other assets	39.6	40.3
TOTAL ASSETS	**$ 4,798.1**	**$ 4,878.9**

The accompanying notes are an integral part of these consolidated condensed financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited – In millions)

	March 31, 2012	December 31, 2011
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 141.6	$ 185.8
Accounts payable to affiliated companies	19.3	36.8
Refundable fuel & natural gas costs	2.6	-
Accrued liabilities	183.6	181.1
Short-term borrowings	174.7	227.1
Current maturities of long-term debt	61.6	62.7
Total current liabilities	**583.4**	**693.5**
Long-term Debt - Net of Current Maturities	1,559.3	1,559.6
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	575.4	575.7
Regulatory liabilities	350.5	345.2
Deferred credits & other liabilities	238.1	239.4
Total deferred credits & other liabilities	**1,164.0**	**1,160.3**
Commitments & Contingencies (Notes 7, 9-12)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 82.0 & 81.9 shares, respectively	694.4	692.6
Retained earnings	808.7	786.2
Accumulated other comprehensive income (loss)	(11.7)	(13.3)
Total common shareholders' equity	**1,491.4**	**1,465.5**
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	**$ 4,798.1**	**$ 4,878.9**

The accompanying notes are an integral part of these consolidated condensed financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED STATEMENTS OF INCOME
(Unaudited – in millions, except per share amounts)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
OPERATING REVENUES		
Gas utility	$ 292.3	$ 356.7
Electric utility	139.4	146.4
Nonutility	172.9	179.5
Total operating revenues	**604.6**	**682.6**
OPERATING EXPENSES		
Cost of gas sold	137.1	195.1
Cost of fuel & purchased power	44.7	59.5
Cost of nonutility revenues	59.5	105.1
Other operating	173.2	141.6
Depreciation & amortization	63.6	59.1
Taxes other than income taxes	16.6	18.9
Total operating expenses	494.7	579.3
OPERATING INCOME	**109.9**	**103.3**
OTHER INCOME (EXPENSE)		
Equity in (losses) of unconsolidated affiliates	(7.6)	(10.9)
Other income – net	3.3	2.4
Total other income (expense)	(4.3)	(8.5)
INTEREST EXPENSE	24.0	26.6
INCOME BEFORE INCOME TAXES	**81.6**	**68.2**
INCOME TAXES	30.3	23.6
NET INCOME	**$ 51.3**	**$ 44.6**
AVERAGE COMMON SHARES OUTSTANDING	**82.0**	**81.7**
DILUTED COMMON SHARES OUTSTANDING	**82.0**	**81.7**
EARNINGS PER SHARE OF COMMON STOCK:		
BASIC	**$ 0.63**	**$ 0.55**
DILUTED	**$ 0.62**	**$ 0.55**
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	**$ 0.350**	**$ 0.345**

The accompanying notes are an integral part of these consolidated condensed financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited – in millions)

	Three Months Ended March 31,	
	2012	2011
Net income	$ 51.3	$ 44.6
Other comprehensive income (loss), before tax:		
Comprehensive income of unconsolidated affiliates	2.9	2.3
Cash flow hedges	-	(3.2)
Other comprehensive income (loss), before tax	2.9	(0.9)
Income taxes related to items of other comprehensive income	(1.3)	0.3
Other comprehensive income (loss), net of tax	1.6	(0.6)
Total comprehensive income	**$ 52.9**	**$ 44.0**

The accompanying notes are an integral part of these consolidated condensed financial statements.

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited – In millions)

	Three Months Ended March 31, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 51.3	$ 44.6
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	63.6	59.1
Deferred income taxes & investment tax credits	13.7	18.5
Equity in losses of unconsolidated affiliates	7.6	10.9
Provision for uncollectible accounts	2.3	5.9
Expense portion of pension & postretirement benefit cost	2.7	2.2
Other non-cash charges - net	1.9	3.2
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	58.1	31.5
Inventories	4.7	54.7
Recoverable/refundable fuel & natural gas costs	5.5	5.1
Prepayments & other current assets	30.4	39.0
Accounts payable, including to affiliated companies	(66.1)	(86.8)
Accrued liabilities	2.4	23.8
Employer contributions to pension & postretirement plans	(4.9)	(29.2)
Changes in noncurrent assets	0.8	8.0
Changes in noncurrent liabilities	(5.2)	(2.1)
Net cash flows from operating activities	**168.8**	**188.4**
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt, net of issuance costs	99.5	-
Dividend reinvestment plan & other common stock issuances	1.6	1.7
Requirements for:		
Dividends on common stock	(28.7)	(28.2)
Retirement of long-term debt	(1.5)	(0.1)
Other financing activities	-	(1.4)
Net change in short-term borrowings	(152.4)	4.0
Net cash flows from financing activities	**(81.5)**	**(24.0)**
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from:		
Other collections	5.5	0.3
Requirements for:		
Capital expenditures, excluding AFUDC equity	(87.2)	(57.7)
Business acquisition, net of cash acquired	-	(82.9)
Net cash flows from investing activities	**(81.7)**	**(140.3)**
Net change in cash & cash equivalents	5.6	24.1
Cash & cash equivalents at beginning of period	8.6	10.4
Cash & cash equivalents at end of period	$ 14.2	$ 34.5

The accompanying notes are an integral part of these consolidated condensed financial statements.

1. Organization and Nature of Operations

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act). Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 570,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to over 313,000 natural gas customers located near Dayton in west central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. Enterprises also has other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. All of the above are collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services.

2. Basis of Presentation

The interim consolidated condensed financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These consolidated condensed financial statements and related notes should be read in conjunction with the Company's audited annual consolidated financial statements for the year ended December 31, 2011, filed with the Securities and Exchange Commission on February 16, 2012, on Form 10-K. Because of the seasonal nature of the Company's operations, the results shown on a quarterly basis are not necessarily indicative of annual results.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

3. Earnings Per Share

The Company uses the two class method to calculate earnings per share (EPS). The two class method is an earnings allocation formula that treats a participating security as having rights to earnings that otherwise would have been available to common shareholders. Under the two class method, earnings for a period are allocated between common shareholders and participating security holders based on their respective rights to receive dividends as if all undistributed book earnings for the period were distributed. Basic EPS is computed by dividing net income attributable to only the common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS includes the impact of stock options and other equity based instruments to the extent the effect is dilutive. The following table illustrates the basic and dilutive EPS calculations for the periods presented in these financial statements.

(In millions, except per share data)	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Numerator:		
Reported net income (Numerator for Basic and Diluted EPS)	$ 51.3	$ 44.6
Denominator:		
Weighted average common shares outstanding (Denominator for Basic and Diluted EPS)	82.0	81.7
Basic EPS	**$ 0.63**	**$ 0.55**
Diluted EPS	**$ 0.62**	**$ 0.55**

For the three months ended March 31, 2011, options to purchase 288,320 additional shares of the Company's common stock were outstanding, but were not included in the computation of diluted EPS because their effect would be antidilutive. The exercise prices for these options were $26.63 to $27.15 for the three months ended March 31, 2011. For the three months ended March 31, 2012, all options were dilutive.

4. Excise and Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $9.3 million and $11.1 million in the three months ended March 31, 2012 and 2011, respectively. Expenses associated with excise and utility receipts taxes are recorded as a component of *Taxes other than income taxes*.

5. Retirement Plans & Other Postretirement Benefits

The Company maintains three qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and three other postretirement benefit plans. The defined benefit pension and other postretirement benefit plans, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The qualified pension plans and the SERP are aggregated under the heading "Pension Benefits." Other postretirement benefit plans are aggregated under the heading "Other Benefits."

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost follows:

	Three Months Ended March 31,			
	Pension Benefits		Other Benefits	
(In millions)	2012	2011	2012	2011
Service cost	$ 1.9	$ 1.7	$ 0.1	$ 0.1
Interest cost	3.9	4.0	0.9	1.1
Expected return on plan assets	(5.3)	(5.3)	-	-
Amortization of prior service cost	0.4	0.4	(0.2)	(0.2)
Amortization of transitional obligation	-	-	0.3	0.3
Amortization of actuarial loss	1.7	1.0	0.1	0.1
Net periodic benefit cost	**$ 2.6**	**$ 1.8**	**$ 1.2**	**$ 1.4**

Employer Contributions to Qualified Pension Plans

Currently, the Company expects to contribute approximately $15 million to its pension plan trusts for 2012. During the three months ended March 31, 2012, contributions of $3.4 million have been made.

6. Supplemental Cash Flow Information

As of March 31, 2012 and December 31, 2011, the Company has accruals related to utility and nonutility plant purchases totaling approximately $17.1 million and $15.9 million, respectively.

7. ProLiance Holdings, LLC

ProLiance Holdings, LLC (ProLiance), a nonutility energy marketing affiliate of Vectren and Citizens Energy Group (Citizens), provides services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance's customers include Vectren's Indiana utilities as well as Citizens' utilities. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. Consistent with its ownership percentage, Vectren is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

Summarized Financial Information

	Three Months Ended March 31,	
(In millions)	2012	2011
Summarized statement of income information:		
Revenues	$ 352.7	$ 500.6
Operating (loss)	(10.9)	(17.2)
ProLiance's net (loss)	(12.4)	(17.4)

(In millions)	As of March 31, 2012		As of December 31, 2011	
Summarized balance sheet information:				
Current assets	$	248.4	$	381.9
Noncurrent assets		55.5		56.1
Current liabilities		171.7		298.5
Noncurrent liabilities		1.0		0.7
Members' equity		149.1		161.5
Accumulated other comprehensive (loss)		(21.3)		(26.0)
Noncontrolling interest		3.4		3.3

Vectren records its 61 percent share of ProLiance's results in *Equity in earnings (losses) of unconsolidated affiliates*. Interest expense and income taxes associated with the investment are recorded separately within the statements of income in those line items. As of March 31, 2012 and December 31, 2011, the Company's investment balance, inclusive of its share of ProLiance's accumulated other comprehensive loss and certain historical book basis differences, is $80.7 million and $85.4 million, respectively. The amounts recorded to *Equity in earnings (losses) of unconsolidated affiliates* related to ProLiance's operations totaled a pre-tax loss of $7.6 million and $10.6 million for the three months ended March 31, 2012 and 2011, respectively.

Investment in Liberty Gas Storage

Liberty Gas Storage, LLC (Liberty), a joint venture between a subsidiary of ProLiance and a subsidiary of Sempra Energy (SE), is a development project for salt-cavern natural gas storage facilities. ProLiance is the minority member with a 25 percent interest, which it accounts for using the equity method. The project was expected to include 17 Bcf of capacity in its North site, and an additional capacity of at least 17 Bcf at the South site. The South site also has the potential for further expansion. The Liberty pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra U.S. Gas & Power, and will connect area LNG regasification terminals to an interstate natural gas transmission system and storage facilities.

In late 2008, the project at the North site was halted due to subsurface and well-completion problems, resulting in an impairment charge related to the North site being recorded in 2009. ProLiance's ability to meet the needs of its customers has not been, nor does it expect it to be, impacted. Approximately 12 Bcf of the storage at the South site, which comprises three of the four FERC certified caverns, is fully completed and tested. As a result of the issues encountered at the North site, Liberty requested and the FERC approved the separation of the North site from the South site. As of March 31, 2012 and December 31, 2011, ProLiance's investment in Liberty approximated $34.6 million and $35.1 million, respectively.

Liberty received a Demand for Arbitration from Williams Midstream Natural Gas Liquids, Inc. ("Williams") on February 8, 2011 related to a Sublease Agreement ("Sublease") between Liberty and Williams at the North site. Williams alleges that Liberty was negligent in its attempt to convert certain salt caverns to natural gas storage and thereby damaged the caverns. Williams alleges damages of $56.7 million. Liberty believes that it has complied with all of its obligations to Williams, including properly terminating the Sublease. Liberty intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams.

Transactions with ProLiance

Purchases from ProLiance for resale and for injections into storage for the three months ended March 31, 2012 and 2011 totaled $79.5 million and $120.1 million, respectively. Amounts owed to ProLiance at March 31, 2012 and December 31, 2011, for those purchases were $19.3 million and $36.8 million, respectively, and are included in *Accounts payable to affiliated companies* in the *Consolidated Condensed Balance Sheets*. Vectren received regulatory approval on April 25, 2006, from the IURC for ProLiance to provide natural gas supply services to the Company's Indiana utilities through March 2011. On March 17, 2011, an order was received from the IURC providing for ProLiance's continued provision of gas supply services to the Company's Indiana utilities and Citizens Energy Group through March 2016. Amounts charged by ProLiance for gas supply services are established by supply agreements with each utility.

8. Financing Activities

On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements. As of December 31, 2011, the Company had reclassified $100 million of short-term borrowings as long-term debt to reflect those borrowings were refinanced with the proceeds received.

9. Commitments & Contingencies

Corporate Guarantees
The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries and unconsolidated affiliates. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary and unconsolidated affiliate obligations in order to allow those subsidiaries and affiliates the flexibility to conduct business without posting other forms of collateral. At March 31, 2012, parent level guarantees support a maximum of $25 million of ESG's performance contracting commitments and warranty obligations and $28 million of other project guarantees. The broader scope of ESG's performance contracting obligations, including those not guaranteed by the parent company, are described below. In addition, the parent company has approximately $23 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $19 million represent letters of credit supporting other nonutility operations. Guarantees issued and outstanding on behalf of unconsolidated affiliates approximated $3 million at March 31, 2012. These guarantees relate primarily to arrangements between ProLiance and various natural gas pipeline operators. The Company has not been called upon to satisfy any obligations pursuant to these parental guarantees and has accrued no significant liabilities related to these guarantees.

As a result of the sale of Vectren Source on December 31, 2011, the Company had $56 million of outstanding guarantees related to this formerly wholly owned subsidiary that remained in effect for 90 days after the closing. The buyer's parent will hold the Company harmless if any amounts are required to be paid pursuant to these guarantees and, within the 90 day period, the buyer was required to provide its own guarantees in substitution for the Company guarantees. This arrangement expired on March 31, 2012.

Performance Guarantees & Product Warranties
In the normal course of business, wholly owned subsidiaries, including ESG, issue performance bonds or other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and/or support warranty obligations. Based on a history of meeting performance obligations and installed products operating effectively, no significant liability or cost has been recognized for the periods presented.

Specific to ESG, in its role as a general contractor in the performance contracting industry, at March 31, 2012, there are 73 open surety bonds supporting future performance. The average face amount of these obligations is $3.6 million, and the largest obligation has a face amount of $23.7 million. The maximum exposure of these obligations is less than these amounts for several factors, including the level of work already completed. At March 31, 2012, approximately 65 percent of work was completed on projects with open surety bonds. A significant portion of these commitments will be fulfilled within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years. The Company has no significant accruals for these warranty obligations as of March 31, 2012.

Legal & Regulatory Proceedings
The Company is party to various legal proceedings, audits, and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations or cash flows.

10. Legislative Matters

Pipeline Safety Law

On January 3, 2012 the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 was signed into law. This new law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability and environmental protection in the transportation of energy products by pipeline. The new law increases federal enforcement authority, grants the federal government expanded authority over pipeline safety, provides for new safety regulations and standards, and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements. The direction of those regulations will be based on the results of the studies and reports required or authorized by the new law and may eventually lead to further regulatory or statutory requirements.

The Company continues to study the impact of the new law and potential new regulations associated with its implementation. At this time, compliance costs and other effects associated with the increased pipeline safety regulations remain uncertain. However, the new law is expected to result in further investment in pipeline inspections, and where necessary, additional modernization of pipeline infrastructure; and therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses. Operating expenses associated with expanded compliance requirements may grow to approximately $9 million annually, with $6 million attributable to the Indiana operations. Related to the Indiana operations, the Company expects to seek recovery under Senate Bill 251 referenced below, or such costs may be recoverable through current tracking mechanisms. Capital investments, driven by the pipeline safety regulations, associated with the Company's Indiana gas utilities are expected to be approximately $80 million over the next five years, which would likely qualify as federally mandated regulatory requirements. In Ohio, capital investments are expected to be approximately $55 million over the next five years. The Company expects to seek recovery of capital investments associated with complying with these federal mandates in accordance with Senate Bill 251 in Indiana and House Bill 95 in Ohio (referenced below).

Indiana Senate Bill 251

In April 2011, Senate Bill 251 was signed into law. While the bill is broad in scope, it allows for cost recovery outside of a base rate proceeding for federal government mandated projects and provides for a voluntary clean energy portfolio standard.

The law applies to both gas and electric utility operations and provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include construction, depreciation, operating and other costs. The remaining 20 percent of those costs are to be deferred for recovery in the utility's next general rate case. The Company is currently evaluating the impact this law may have on its operations, including applicability to expenditures associated with the integrity, safety, and reliable operation of natural gas pipelines and facilities; ash disposal; water regulations; and air pollution control, including greenhouse gas emissions, among other federally mandated projects and potential projects.

Ohio House Bill 95

In June 2011, Ohio House Bill 95 was signed into law. The law adjusts, among other things, the manner in which gas utilities file for rate changes, including the implementation of base rate changes, alternative rate plans, and automatic rate adjustment mechanisms. Outside of a base rate proceeding, the legislation permits a natural gas company to apply for recovery of a capital expenditure program for infrastructure expansion, upgrade, or replacement; installation, upgrade, or replacement of information technology systems; or any program necessary to comply with government regulation. Once such application is approved, the legislation authorizes deferral of program costs, such as depreciation, property taxes, and debt-related carrying costs. On February 3, 2012, the Company initiated a filing under House Bill 95. This filing requests accounting authority to defer depreciation, debt-related post in service carrying costs and property taxes for its approximate $25 million fifteen month capital expenditure program ending on December 31, 2012. The capital expenditure program includes infrastructure expansion and improvements not covered by the Company's distribution replacement rider as well as expenditures necessary to comply with PUCO rules, regulations and orders. The Company's approach is consistent with approaches made by other Ohio utilities. A procedural schedule associated with the filing has been set and all respective responses have been submitted. It is anticipated the PUCO will act on the Company's filing and the flings of the other Ohio utilities later this year.

11. Environmental Matters

Air Quality

Cross-State Air Pollution Rule (Formerly Clean Air Interstate Rule (CAIR))

On July 7, 2011, EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSPAR is the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO_2 emissions beginning January 1, 2010, with a second phase of reductions in 2015.

In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO_2 and NOx allowances, CSPAR reduces the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSPAR sets individual state caps for SO_2 and NOx emissions. However, unlike CAIR in which states allocated allowances through state implementation plans, CSPAR allowances were allocated to individual units directly through the federal rule. As finalized, CSAPR requires a 71 percent reduction of SO_2 emissions compared to 2005 national levels and a 52 percent reduction of NOx emissions compared to 2005 national levels and that such reductions are to be achieved with initial step reductions beginning January 1, 2012, with final compliance to be achieved in 2014. Multiple administrative and judicial challenges have been filed, including requests to stay CSPAR's implementation.

On December 30, 2011, the Court granted a stay of CSPAR and ordered expedited briefing schedules be submitted by January 18, 2012, which allowed for completion of briefing and a hearing in April 2012. Two primary issues are before the Court for review: (1) EPA's use of air modeling data (as opposed to exclusive reliance on actual monitoring data) to support state contribution levels, and (2) EPA's allocation of allowances directly through a federal implementation plan as opposed to setting state caps and providing states the opportunity to submit individual state implementation plans. In addition, there are initiatives in the Congress that, if adopted, would suspend CSPAR's implementation. A final ruling is expected later this year.

Utility Hazardous Air Pollutants (HAPs) Rule

On December 21, 2011, the EPA finalized the Utility HAPs rule. The HAPs Rule is the EPA's response to the US Court of Appeals for the District of Columbia vacating the Clean Air Mercury Rule (CAMR) in 2008. CAMR was originally established in 2005 as a nation-wide mercury emission allowance cap and trade system which sought to reduce utility emissions of mercury starting in 2010.

The HAPs rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium) and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSPAR's implementation by the Congress also apply to the implementation of the HAPs rule. The reviewing court has yet to rule on any requests to stay the implementation of the HAPs rule.

Conclusions Regarding Air Regulations

To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal fired generating fleet is 100 percent scrubbed for SO_2 and 90 percent controlled for NOx.

Utilization of the Company's NOx and SO_2 allowances can be impacted as these regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

The Company is currently reviewing the sufficiency of its existing pollution control equipment in relation to the requirements described in CSPAR and the Utility HAPs Rule. Based upon an initial review of the final rules, including minor revisions made to CSPAR in October 2011, the Company believes that it will be able to meet these requirements with its existing suite of pollution control equipment and the anticipated allotment of new emission allowances. However, it is possible some minor modifications to the control equipment and additional operating expenses could be required. The Company believes that such additional costs, if necessary, would be recoverable under Indiana Senate Bill 251 referenced above.

Notice of Violation Received
The Company received a notice of violation (NOV) from the EPA pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. Based on the Company's understanding of the New Source Review reform in effect when the equipment was installed, it is the Company's position that its SCR project was exempted from such requirements. At this time the Company is reviewing the potential impact this NOV could have on operating costs. To the extent costs to comply increase, they should be recoverable under Indiana law.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2012. Depending on the final rule and on the Company's facts and circumstances, capital investments could be in the $40 million range if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations would likely qualify as federally mandated regulatory requirements under Indiana Senate Bill 251 referenced above.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules may not be finalized in 2012 given oversight hearings, congressional interest, and other factors.

At this time, the majority of the Company's ash is being beneficially reused. However, the alternatives proposed would require some retrofitting or closure of existing ash ponds. The Company estimates capital expenditures to comply could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase slightly or be impacted by as much as $5 million. Costs for compliance with these regulations would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above.

Climate Change
In April 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress. The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. In April 2012, the USEPA issued its proposed new source performance standards for greenhouse gases applicable to new construction. This proposed rule does not apply to existing sources, such as Vectren's generating facilities. The USEPA has not indicated when it intends to propose standards for existing sources.

Numerous competing federal legislative proposals have also been introduced in recent years that involve carbon, energy efficiency, and renewable energy. Comprehensive energy legislation at the federal level continues to be debated, but there has been little progress to date. The progression of regional initiatives throughout the United States has also slowed.

Impact of Legislative Actions & Other Initiatives is Unknown
If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other greenhouse gases or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants, nonutility coal mining operations, and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control greenhouse gas emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures would be recoverable from customers through Senate Bill 251. Customer rates may also be impacted should decisions be made to reduce the level of sales to municipal and other wholesale customers in order to meet emission targets.

Manufactured Gas Plants
In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds at these sites.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/feasibility study (RI/FS) was completed at one of the sites under an agreed order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plants sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it reasonably expects to incur totaling approximately $41.7 million ($23.2 million at Indiana Gas and $18.5 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. SIGECO filed a declaratory judgment action against its insurance carriers seeking a judgment finding its carriers liable under the policies for coverage of further investigation and any necessary remediation costs that SIGECO may accrue under the VRP program and/or another site subject to a lawsuit that has been settled. In November 2011, the Court ruled on two motions for summary judgment, finding for SIGECO and against certain insurers on indemnification and defense obligations in the policies at issue. SIGECO has settlement agreements with all known insurance carriers and has recorded approximately $15.2 million of expected insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require some level of additional remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of March 31, 2012 and December 31, 2011, respectively, approximately $4.7 million and $6.5 million of accrued, but not yet spent, costs are included in *Other Liabilities* related to both the Indiana Gas and SIGECO sites.

12. Rate & Regulatory Matters

Vectren South Electric Base Rate Filing

On December 11, 2009, Vectren South filed a request with the IURC to adjust its base electric rates. The requested increase in base rates addressed capital investments, a modified electric rate design that would facilitate a partnership between Vectren South and customers to pursue energy efficiency and conservation, and new energy efficiency programs to complement those currently offered for natural gas customers. The IURC issued an order in the case on April 27, 2011. The order provides for an approximate $28.6 million revenue increase to recover costs associated with approximately $325 million in system upgrades that were completed in the three years leading up to the December 2009 filing and modest increases in maintenance and operating expenses. The approved revenue increase is based on rate base of $1,295.6 million, return on equity of 10.4 percent and an overall rate of return of 7.29 percent. The new rates were effective May 3, 2011. The IURC, in its order, denied the Company's request for implementation of the decoupled rate design, which is discussed further below. Addressing issues raised in the case concerning coal supply contracts and related costs, the IURC found that current coal contracts remain effective and that a prospective review process of future procurement decisions would be initiated.

Coal Procurement Procedures

Vectren South submitted a request for proposal in April 2011 regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, Vectren South has reached an agreement in principle for multi-year purchases with two suppliers, one of which is Vectren Fuels, Inc. Consistent with the IURC direction in the electric rate case, a sub docket proceeding was established to review the Company's prospective coal procurement procedures, and the Company submitted evidence related to its recent request for proposal (RFP) and those coal procurement procedures to the IURC in September 2011. In March 2012, the IURC issued its order in the sub docket. The order concluded that Vectren South's 2011 RFP process resulted in prices at the lowest fuel cost reasonably possible. The IURC will continue to regularly monitor Vectren South's procurement process in future fuel adjustment proceedings.

Vectren South Electric Fuel Cost Reduction

In the spring of 2011, Vectren secured contracts for lower coal costs through a formal bidding process. This lower-priced coal is expected to start being delivered and used at Vectren's power plants by late 2012 to early 2013 and beyond. On December 5, 2011 within the quarterly FAC filing, Vectren South submitted a joint proposal with the OUCC to reduce its fuel costs by accelerating the impact of lower cost coal contracts to be effective after 2012. The agreement to accelerate savings into early 2012 means that the existing 2012 coal costs that are above the new, lower prices will be deferred to a regulatory asset and recovered over a six-year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with a positive impact to customer's rates effective February 1, 2012. Deferrals also include a reduction in the value of the coal inventory at December 31, 2011 of approximately $17.7 million to reflect existing coal inventory at the new, lower price. Deferrals related to coal purchases in 2012 have totaled approximately $9.7 million, bringing the total deferred balance as of March 2012 to $27.4 million.

Vectren South Electric Demand Side Management Program Filing

On August 16, 2010, Vectren South filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed are consistent with a December 9, 2009 order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South service territory that complies with the IURC's energy saving targets. Consistent with the Company's proposal, the order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs; and 4) deferral of lost margin up to $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the order received April 27, 2011. On January 26, 2012, the Company requested approval from the IURC of a recovery mechanism within the existing Demand Side Management Adjustment (DSMA) for lost margins resulting from small customer participation in the Company's DSM programs. The filing included a request for recovery of the $1 million deferred in 2011, and a request for continued deferral of lost margins in 2012 until such point as these lost margins are included in DSMA rates. The evidentiary hearing in this matter is scheduled for June 5, 2012.

Vectren South Electric Dense Pack Filing
On September 14, 2011, Vectren South filed a petition with the IURC seeking recovery of and return on the capital investment in dense pack technology to improve the efficiency of its A.B. Brown Generating Station. This investment is expected to be approximately $32 million over the next two years, of which approximately $22 million has been invested to date. This technology is expected to allow the A.B. Brown units to run at least 5 percent more efficient, thereby burning less fuel, and reducing fuel costs and emissions of pollutants. In the Company's base rate order issued in April 2011, the IURC authorized deferred accounting treatment associated with this investment. Indiana statute also provides for timely recovery of investments, with a return, in instances where the investment increases the efficiency of existing generating plants that are fueled by coal. Several parties have intervened in the case and are requesting that the IURC deny recovery of these project costs outside of a base rate proceeding. A hearing was held by the IURC in February 2012 and proposed orders were submitted by the parties in March 2012. An order on timely recovery is expected later in 2012.

Vectren North Reporting Location Consolidation Proceeding
Vectren North implemented a reporting location consolidation plan in 2011 and converted certain reporting locations into staging areas throughout the Vectren North territory. On May 26, 2011, the International Brotherhood of Electrical Workers Local 1393, United Steel Workers Locals 12213 and 7441 and others (the "Complainants") filed a formal complaint with the IURC claiming that implementation of the consolidation plan by Vectren North endangers public safety and impairs Vectren North's ability to provide adequate, safe and reliable service. The Complainants asked the IURC to require Vectren North to reopen previously consolidated reporting locations and maintain and staff those locations. A hearing in this case was held in February 2012. Complainants submitted a proposed order in March and Vectren North submitted a reply brief and a proposed order in April. The case will be fully briefed as of the first of May and the Company expects the IURC to issue a final order in this matter some time in 2012.

VEDO Continues the Process to Exit the Merchant Function
On August 20, 2008, the PUCO approved the results of an auction selecting qualified wholesale suppliers to provide the gas commodity to the Company for resale to its customers at auction-determined standard pricing. This standard pricing was comprised of the monthly NYMEX settlement price plus a fixed adder. This standard pricing, which was effective from October 1, 2008 through March 31, 2010, was the initial step in exiting the merchant function in the Company's Ohio service territory. The approach eliminated the need for monthly gas cost recovery (GCR) filings and prospective PUCO GCR audits.

The second phase of the exit process began on April 1, 2010. During this phase, the Company no longer sells natural gas directly to customers. Rather, state-certified Competitive Retail Natural Gas Suppliers, that are successful bidders in a similar regulatory-approved auction, sell the gas commodity to specific customers for a 12-month period at auction-determined standard pricing. During the second phase, VEDO conducted its third retail auction on January 31, 2012 to address the 12-month term beginning April 1, 2012. The results of that auction were approved by the PUCO on February 1, 2012. Consistent with current practice, customers continue to receive a single bill for the commodity as well as the delivery component of natural gas service from VEDO.

The PUCO provided for an Exit Transition Cost rider, which allows the Company to recover costs associated with the transition process. Exiting the merchant function has not had a material impact on earnings or financial condition.

13. Impact of Recently Issued Accounting Principles

Other Comprehensive Income (OCI)
In 2011, the FASB issued new accounting guidance regarding the presentation of comprehensive income within financial statements. The new guidance will require entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. Under the two-statement approach, the first statement would include components of net income, which is consistent with the income statement format used today, and the second statement would include components of OCI. The guidance does not change the items that must be reported in OCI. The new guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and retrospective application is required. The Company adopted this guidance, as amended for condensed quarterly reporting, for the quarterly reporting period ending March 31, 2012 by reporting comprehensive income as required.

Goodwill Testing
In September 2011, the FASB issued new accounting guidance regarding testing goodwill for impairment. The new guidance will allow the Company an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Using the new guidance, the Company no longer would be required to calculate the fair value of a reporting unit unless the Company determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The Company considered this option during its quarterly reporting period ending March 31, 2012 and concluded the continuation of the use of a quantitative approach is appropriate.

Fair Value Measurement and Disclosure
In May 2011, the FASB issued accounting guidance to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and International Financial Reporting Standards (IFRS). The amendments are not intended to change the application of the current fair value requirements, but to clarify the application of existing requirements. The guidance does change particular principles or requirements for measuring fair value or disclosing information about fair value measurements. To improve consistency, language has been changed to ensure that U.S. GAAP and IFRS fair value measurement and disclosure requirements are described in the same way. The Company adopted this guidance for its quarterly reporting period ending March 31, 2012. The adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

14. Fair Value Measurements

The carrying values and estimated fair values using primarily Level 2 assumptions of the Company's other financial instruments follow:

	March 31, 2012		December 31, 2011	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$ 1,620.9	$ 1,776.5	$ 1,622.3	$ 1,804.4
Short-term borrowings	174.7	174.7	227.1	227.1
Cash & cash equivalents	14.2	14.2	8.6	8.6

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities recorded at fair value outstanding.

Certain methods and assumptions must be used to estimate the fair value of financial instruments. The fair value of the Company's long-term debt was estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for instruments with similar characteristics. Because of the maturity dates and variable interest rates of short-term borrowings and cash & cash equivalents, those carrying amounts approximate fair value. Because of the inherent difficulty of estimating interest rate and other market risks, the methods used to estimate fair value may not always be indicative of actual realizable value, and different methodologies could produce different fair value estimates at the reporting date.

Under current regulatory treatment, call premiums on reacquisition of long-term debt are generally recovered in customer rates over the life of the refunding issue or over a 15-year period. Accordingly, any reacquisition would not be expected to have a material effect on the Company's results of operations.

Because of the customized nature of notes receivable investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At March 31, 2012 and December 31, 2011, the fair value for these financial instruments was not estimated. The carrying value of notes receivable, inclusive of any accrued interest and net of impairment reserves, was approximately $2.1 million at March 31, 2012 and December 31, 2011.

15. Segment Reporting

The Company segregates its operations into three groups: 1) Utility Group, 2) Nonutility Group, and 3) Corporate and Other.

The Utility Group is comprised of Vectren Utility Holdings, Inc.'s operations, which consist of the Company's regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between Gas Utility Services and Electric Utility Services. Gas Utility Services provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio. Electric Utility Services provides electric distribution services to southwestern Indiana, and includes the Company's power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the Utility Group reports three segments: Gas Utility Services, Electric Utility Services, and Other operations.

The Nonutility Group reports five segments: Infrastructure Services, Energy Services, Coal Mining, Energy Marketing, and Other Businesses. Segment information below reflects the March 31, 2011 acquisition of Minnesota Limited, Inc. in the Infrastructure Services segment and the December 31, 2011 sale of Vectren Source in Energy Marketing segment.

Corporate and Other includes unallocated corporate expenses such as advertising and charitable contributions, among other activities, that benefit the Company's other operations. Net income is the measure of profitability used by management for all operations. Information related to the Company's reportable segments is summarized as follows:

	Three Months Ended March 31,	
(In millions)	2012	2011
Revenues		
Utility Group		
Gas Utility Services	$ 292.3	$ 356.7
Electric Utility Services	139.4	146.4
Other Operations	9.9	11.0
Eliminations	(9.5)	(10.5)
Total Utility Group	**432.1**	**503.6**
Nonutility Group		
Infrastructure Services	117.5	47.2
Energy Services	22.2	23.6
Coal Mining	58.5	69.4
Energy Marketing	-	74.0
Other Businesses	0.1	-
Total Nonutility Group	**198.3**	**214.2**
Eliminations	(25.8)	(35.2)
Consolidated Revenues	**$ 604.6**	**$ 682.6**
Profitability Measure - Net Income		
Utility Group		
Gas Utility Services	$ 37.5	$ 36.1
Electric Utility Services	15.6	8.6
Other Operations	2.9	3.9
Utility Group Net Income	**56.0**	**48.6**
Nonutility Group Net Income (Loss)		
Infrastructure Services	3.0	(2.9)
Energy Services	(1.7)	(1.4)
Coal Mining	(0.3)	1.6
Energy Marketing	(5.9)	(0.4)
Other Businesses	0.1	(0.3)
Nonutility Group Net Income (Loss)	**(4.8)**	**(3.4)**
Corporate & Other Group Net Income (Loss)	0.1	(0.6)
Consolidated Net Income	**$ 51.3**	**$ 44.6**

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also earns a return on shared assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act). Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 570,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to over 313,000 natural gas customers located near Dayton in west central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. Enterprises also has other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. All of the above are collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services.

Executive Summary of Consolidated Results of Operations

In this discussion and analysis, the Company analyzes contributions to consolidated earnings and earnings per share from its Utility Group and Nonutility Group separately since each operates independently requiring distinct competencies and business strategies, offers different energy and energy related products and services, and experiences different opportunities and risks.

The Utility Group generates revenue primarily from the delivery of natural gas and electric service to its customers. The primary source of cash flow for the Utility Group results from the collection of customer bills and the payment for goods and services procured for the delivery of gas and electric services. The activities of, and revenues and cash flows generated by, the Nonutility Group are closely linked to the utility industry, and the results of those operations are generally impacted by factors similar to those impacting the overall utility industry. In addition, there are other operations, referred to herein as Corporate and Other, that include unallocated corporate expenses such as advertising and charitable contributions, among other activities.

The Company has in place a disclosure committee that consists of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company's SEC filings. The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company's 2011 annual report filed on Form 10-K.

Net income and earnings per share, in total and by group, for the three months ended March 31, 2012 and 2011 follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2012	2011
Net income (loss)	$ 51.3	$ 44.6
Attributed to:		
Utility Group	56.0	48.6
Nonutility Group	(4.8)	(3.4)
Corporate & other	0.1	(0.6)
Basic EPS	$ 0.63	$ 0.55
Attributed to:		
Utility Group	0.69	0.59
Nonutility Group	(0.06)	(0.04)
Corporate & other	-	-

Utility Group

In 2012, the Utility Group's first quarter earnings were $56.0 million compared to $48.6 million in 2011, an increase of $7.4 million. The first quarter of 2012 has been positively impacted by new electric base rates implemented on May 3, 2011 and negatively impacted by extremely mild winter weather. The Utility Group also was impacted by lower interest expense as a result of refinancing's occurring in the last quarter of 2011 and first quarter of 2012 and lower other operating costs.

Gas Utility Services

Gas utility services earned $37.5 million during the three months ended March 31, 2012, compared to earnings of $36.1 million in the first quarter of 2011. Results in 2012 have been impacted by lower uncollectible accounts expense driven primarily by lower gas costs and lower interest expense due to the recent refinancing activity. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 71 percent of normal in Indiana and 82 percent of normal in Ohio had only a slightly negative impact on margin.

Electric utility services

The electric operations earned $15.6 million during the three months ended March 31, 2012, compared to $8.6 million in the prior year period. Factors impacting electric results were consistent with those impacting the overall Utility Group including increased base rates, mild weather, and lower other operating and interest costs.

Management estimates the impact of very mild weather on retail electric customer electric margin, compared to normal temperatures, to be approximately $3.6 million unfavorable in the first quarter of 2012. This compares to the first quarter of 2011, where management estimated a $0.2 million unfavorable impact on margin compared to normal.

Other utility operations

Year to date in 2012 earnings from other utility operations were $2.9 million compared to $3.9 million in 2011.

Nonutility Group

In the first quarter of 2012, the Nonutility Group incurred a net loss of $4.8 million, which compares to a net loss of $3.4 million in 2011. Infrastructure Services results increased $5.9 million quarter over quarter, reflective of increased demand for services. ProLiance's results increased quarter over quarter as well, while Coal Mining and Energy Services results have decreased quarter over quarter. Seasonal earnings in the first quarter of 2011 were $7.1 million from retail energy marketer Vectren Source, which was sold on December 31, 2011, and $2.8 million for the full year in 2011.

Dividends

Dividends declared for the three months ended March 31, 2012 were $0.350 per share, compared to $0.345 per share for the same period in 2011.

Use of Non-GAAP Performance Measures and Per Share Measures

Per share earnings contributions of the Utility Group, Nonutility Group, and Corporate and Other are presented and are non-GAAP measures. Such per share amounts are based on the earnings contribution of each group included in Vectren's consolidated results divided by Vectren's basic average shares outstanding during the period. The earnings per share of the groups do not represent a direct legal interest in the assets and liabilities allocated to the groups, but rather represent a direct equity interest in Vectren Corporation's assets and liabilities as a whole. These non-GAAP measures are used by management to evaluate the performance of individual businesses. In addition, other items giving rise to period over period variances, such as weather, may be presented on an after tax and per share basis. These amounts are calculated at a statutory tax rate divided by Vectren's basic average shares outstanding during the period. Accordingly, management believes these measures are useful to investors in understanding each business' contribution to consolidated earnings per share and in analyzing consolidated period to period changes and the potential for earnings per share contributions in future periods. Reconciliations of the non-GAAP measures to their most closely related GAAP measure of consolidated earnings per share are included throughout this discussion and analysis. The non-GAAP financial measures disclosed by the Company should not be considered a substitute for, or superior to, financial measures calculated in accordance with GAAP, and the financial results calculated in accordance with GAAP.

Detailed Discussion of Results of Operations

Following is a more detailed discussion of the results of operations of the Company's Utility and Nonutility operations. The detailed results of operations for these groups are presented and analyzed before the reclassification and elimination of certain intersegment transactions necessary to consolidate those results into the Company's *Consolidated Condensed Statements of Income*.

Results of Operations of the Utility Group

The Utility Group is comprised of Utility Holdings' operations and consists of the Company's regulated operations and other operations that provide information technology and other support services to those regulated operations. Regulated operations consist of a natural gas distribution business that provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio and an electric transmission and distribution business, which provides electric distribution services to southwestern Indiana, and the Company's power generating and wholesale power operations. In total, these regulated operations supply natural gas and/or electricity to over one million customers. Utility Group operating results before certain intersegment eliminations and reclassifications for the three months ended March 31, 2012 and 2011, follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2012	2011
OPERATING REVENUES		
Gas utility	$ 292.3	$ 356.7
Electric utility	139.4	146.4
Other	0.4	0.5
Total operating revenues	**432.1**	**503.6**
OPERATING EXPENSES		
Cost of gas sold	137.1	195.1
Cost of fuel & purchased power	44.7	59.5
Other operating	79.9	86.9
Depreciation & amortization	48.6	48.2
Taxes other than income taxes	15.9	18.0
Total operating expenses	326.2	407.7
OPERATING INCOME	**105.9**	**95.9**
OTHER INCOME - NET	2.2	1.7
INTEREST EXPENSE	17.7	20.4
INCOME BEFORE INCOME TAXES	**90.4**	**77.2**
INCOME TAXES	34.4	28.6
NET INCOME	**$ 56.0**	**$ 48.6**
CONTRIBUTION TO VECTREN BASIC EPS	**$ 0.69**	**$ 0.59**

Utility Group Margin

Throughout this discussion, the terms Gas Utility margin and Electric Utility margin are used. Gas Utility margin is calculated as *Gas utility revenues* less the *Cost of gas sold*. Electric Utility margin is calculated as *Electric utility revenues* less *Cost of fuel & purchased power*. The Company believes Gas Utility and Electric Utility margins are better indicators of relative contribution than revenues since gas prices and fuel and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers. Following is a discussion and analysis of margin generated from regulated utility operations.

Gas Utility Margin (Gas utility revenues less Cost of gas sold)

Gas utility margin and throughput by customer type follows:

(In millions)	Three Months Ended March 31, 2012	2011
Gas utility revenues	$ 292.3	$ 356.7
Cost of gas sold	137.1	195.1
Total gas utility margin	**$ 155.2**	**$ 161.6**
Margin attributed to:		
Residential & commercial customers	$ 135.1	$ 139.7
Industrial customers	16.5	17.6
Other	3.6	4.3
Total gas utility margin	**$ 155.2**	**$ 161.6**
Sold & transported volumes in MMDth attributed to:		
Residential & commercial customers	40.8	52.8
Industrial customers	27.8	28.8
Total sold & transported volumes	**68.6**	**81.6**

For the three months ended March 31, 2012, gas utility margins were $155.2 million and compared to 2011 decreased $6.4 million. Approximately $5.4 million of this decrease results from the impact of low natural gas prices and mild weather on revenue taxes, late and reconnect fees, and volumetric pass through costs. Large customer margin, net of the impacts of regulatory initiatives and tracked costs, decreased by $0.9 million due primarily to lower volumes sold, largely due to warmer weather. Weather also had some impact on small customers, reducing margin $0.7 million quarter over quarter. Returns generated on investments in bare steel/ cast iron and distribution riser replacement in Ohio increased margins $0.7 million quarter over quarter.

Electric Utility Margin (Electric utility revenues less Cost of fuel & purchased power)
Electric utility margin and volumes sold by customer type follows:

(In millions)	Three Months Ended March 31, 2012	2011
Electric utility revenues	$ 139.4	$ 146.4
Cost of fuel & purchased power	44.7	59.5
Total electric utility margin	**$ 94.7**	**$ 86.9**
Margin attributed to:		
Residential & commercial customers	$ 58.7	$ 54.0
Industrial customers	25.3	23.4
Other customers	1.8	1.9
Subtotal: retail	**$ 85.8**	**$ 79.3**
Wholesale power & transmission system margin	8.9	7.6
Total electric utility margin	**$ 94.7**	**$ 86.9**
Electric volumes sold in GWh attributed to:		
Residential & commercial customers	631.1	681.6
Industrial customers	681.7	661.9
Other customers	5.9	5.9
Total retail volumes sold	**1,318.7**	**1,349.4**

Retail
Electric retail utility margins were $85.8 million for the three months ended March 31, 2012, and compared to 2011 increased by $6.5 million. Margin across all customer classes increased by $7.6 million from new base rates effective May 3, 2011. Large customer margin increased $0.7 million on increasing volumes. Increases were offset primarily by the impacts of mild weather which reduced residential and commercial usage and margin.

Margin from Wholesale Electric Activities
Periodically, generation capacity is in excess of native load. The Company markets and sells this unutilized generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales occur into the MISO Day Ahead and Real Time markets. Further detail of *Wholesale* activity follows:

(In millions)	Three Months Ended March 31, 2012	2011
Off-system sales	$ 3.0	$ 2.0
Transmission system sales	5.9	5.6
Total wholesale margin	**$ 8.9**	**$ 7.6**

The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of MISO's regional transmission expansion plans. Margin associated with these projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $5.9 million during the three months ended March 31, 2012, compared to $5.6 million for the same period in 2011. The increase in these transmission system sales is principally due to the increased investment in qualifying projects.

One such project currently under construction meeting these expansion plan criteria is an interstate 345 Kv transmission line that will connect Vectren's A.B. Brown Generating Station to a station in Indiana owned by Duke Energy to the north and to a station in Kentucky owned by Big Rivers Electric Corporation to the south. During the construction of these transmission assets and while these assets are in service, SIGECO will recover an approximate 10 percent return, inclusive of the FERC approved equity rate of return of 12.38 percent, on capital investments through a rider mechanism which is projected annually and reconciled the following year based on actual results. Of the total investment, which is expected to approximate $105 million, the Company has invested approximately $83 million as of March 31, 2012. The north leg of this expansion was placed in service in November 2010, and the south leg of this project is expected to be operational later in 2012.

For the three months ended March 31, 2012, margin from off-system sales was $3.0 million, compared to $2.0 million for the three months ended March 31, 2011. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million be shared equally with customers. This compares to a $10.5 million sharing threshold established in 2007. Results for the periods presented reflect the impact of that sharing recognized during the 2012 first quarter which increased margin year over year and offset the effects of lower volumes sold. Off-system sales totaled 48.7 GWh and 183.9 GWh during the three months ended March 31, 2012 and 2011, respectively, reflecting reduced opportunities in 2012 due to the mild weather.

Utility Group Operating Expenses

Other Operating
For the three months ended March 31, 2012, other operating expenses were $79.9 million, a decrease of $7.0 million, compared to 2011. The decrease results primarily from a $3.7 million in lower uncollectible accounts expense driven by lower gas prices increasing customer's ability to pay and lower power supply operating costs of $1.5 million driven primarily by reduced variable production costs associated with mild winter weather. The remaining decrease is primarily attributable to lower pass through operating costs that are offset with lower Gas utility margin.

Depreciation & Amortization
For the three months ended March 31, 2012, *depreciation and amortization* expense was $48.6 million, compared to $48.2 million in 2011. The increas reflects increased plant placed into service, offset by lower amortization of certain deferred costs pursuant to the May 2011 electric base rate order. Such decreased amortizations were $0.9 million in 2012.

Taxes Other Than Income Taxes
Taxes other than income taxes were $15.9 million for the quarter, a decrease of $2.1 million compared to the prior year quarter. The decrease is primarily attributable to lower usage taxes associated with lower gas and fuel costs. These expenses are offset dollar-for-dollar with lower gas utility and electric utility revenues.

Other Income-Net
Other income-net reflects income of $2.2 million for the quarter, an increase of $0.5 million compared to the prior year quarter. The increase reflects increased AFUDC on gas utility construction projects.

Interest Expense
Interest expense was $17.7 million for the first quarter of 2012, a decrease of $2.7 million compared to 2011. The lower expense reflects fourth quarter of 2011 refinancing activity in which $250 million of long-term debt with a 6.625 percent interest rate matured and was replaced with $150 million of new long-term debt with an average interest rate of 5.12 percent and $100 million of short-term borrowings. During the fourth quarter of 2011, the Company also called $96.2 million of long-term debt at a rate of 5.95 percent and replaced that issuance in February 2012 with new debt at a rate of 5.0 percent.

Income Taxes
In 2012, federal and state income taxes were $34.4 million for the quarter, an increase of $5.8 million compared to the prior year quarter. The increase is primarily due to higher pre-tax income.

Legislative Matters

Pipeline Safety Law

On January 3, 2012 the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 was signed into law. This new law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability and environmental protection in the transportation of energy products by pipeline. The new law increases federal enforcement authority, grants the federal government expanded authority over pipeline safety, provides for new safety regulations and standards, and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements. The direction of those regulations will be based on the results of the studies and reports required or authorized by the new law and may eventually lead to further regulatory or statutory requirements.

The Company continues to study the impact of the new law and potential new regulations associated with its implementation. At this time, compliance costs and other effects associated with the increased pipeline safety regulations remain uncertain. However, the new law is expected to result in further investment in pipeline inspections, and where necessary, additional modernization of pipeline infrastructure; and therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses. Operating expenses associated with expanded compliance requirements may grow to approximately $9 million annually, with $6 million attributable to the Indiana operations. Related to the Indiana operations, the Company expects to seek recovery under Senate Bill 251 referenced below, or such costs may be recoverable through current tracking mechanisms. Capital investments, driven by the pipeline safety regulations, associated with the Company's Indiana gas utilities are expected to be approximately $80 million over the next five years, which would likely qualify as federally mandated regulatory requirements. In Ohio, capital investments are expected to be approximately $55 million over the next five years. The Company expects to seek recovery of capital investments associated with complying with these federal mandates in accordance with Senate Bill 251 in Indiana and House Bill 95 in Ohio (referenced below).

Indiana Senate Bill 251

In April 2011, Senate Bill 251 was signed into law. While the bill is broad in scope, it allows for cost recovery outside of a base rate proceeding for federal government mandated projects and provides for a voluntary clean energy portfolio standard.

The law applies to both gas and electric utility operations and provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include construction, depreciation, operating and other costs. The remaining 20 percent of those costs are to be deferred for recovery in the utility's next general rate case. The Company is currently evaluating the impact this law may have on its operations, including applicability to expenditures associated with the integrity, safety, and reliable operation of natural gas pipelines and facilities; ash disposal; water regulations; and air pollution control, including greenhouse gas emissions, among other federally mandated projects and potential projects.

Ohio House Bill 95

In June 2011, Ohio House Bill 95 was signed into law. The law adjusts, among other things, the manner in which gas utilities file for rate changes, including the implementation of base rate changes, alternative rate plans, and automatic rate adjustment mechanisms. Outside of a base rate proceeding, the legislation permits a natural gas company to apply for recovery of a capital expenditure program for infrastructure expansion, upgrade, or replacement; installation, upgrade, or replacement of information technology systems; or any program necessary to comply with government regulation. Once such application is approved, the legislation authorizes deferral of program costs, such as depreciation, property taxes, and debt-related carrying costs. On February 3, 2012, the Company initiated a filing under House Bill 95. This filing requests accounting authority to defer depreciation, debt-related post in service carrying costs and property taxes for its approximate $25 million fifteen month capital expenditure program ending on December 31, 2012. The capital expenditure program includes infrastructure expansion and improvements not covered by the Company's distribution replacement rider as well as expenditures necessary to comply with PUCO rules, regulations and orders. The Company's approach is consistent with approaches made by other Ohio utilities. A procedural schedule associated with the filing has been set and all respective responses have been submitted. It is anticipated the PUCO will act on the Company's filing and the flings of the other Ohio utilities later this year.

Environmental Matters

Air Quality

Cross-State Air Pollution Rule (Formerly Clean Air Interstate Rule (CAIR))

On July 7, 2011, EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSPAR is the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO_2 emissions beginning January 1, 2010, with a second phase of reductions in 2015.

In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO_2 and NOx allowances, CSPAR reduces the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSPAR sets individual state caps for SO_2 and NOx emissions. However, unlike CAIR in which states allocated allowances through state implementation plans, CSPAR allowances were allocated to individual units directly through the federal rule. As finalized, CSAPR requires a 71 percent reduction of SO_2 emissions compared to 2005 national levels and a 52 percent reduction of NOx emissions compared to 2005 national levels and that such reductions are to be achieved with initial step reductions beginning January 1, 2012, with final compliance to be achieved in 2014. Multiple administrative and judicial challenges have been filed, including requests to stay CSPAR's implementation.

On December 30, 2011, the Court granted a stay of CSPAR and ordered expedited briefing schedules be submitted by January 18, 2012, which allowed for completion of briefing and a hearing in April 2012. Two primary issues are before the Court for review: (1) EPA's use of air modeling data (as opposed to exclusive reliance on actual monitoring data) to support state contribution levels, and (2) EPA's allocation of allowances directly through a federal implementation plan as opposed to setting state caps and providing states the opportunity to submit individual state implementation plans. In addition, there are initiatives in the Congress that, if adopted, would suspend CSPAR's implementation. A final ruling is expected later this year.

Utility Hazardous Air Pollutants (HAPs) Rule

On December 21, 2011, the EPA finalized the Utility HAPs rule. The HAPs Rule is the EPA's response to the US Court of Appeals for the District of Columbia vacating the Clean Air Mercury Rule (CAMR) in 2008. CAMR was originally established in 2005 as a nation-wide mercury emission allowance cap and trade system which sought to reduce utility emissions of mercury starting in 2010.

The HAPs rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium) and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSPAR's implementation by the Congress also apply to the implementation of the HAPs rule. The reviewing court has yet to rule on any requests to stay the implementation of the HAPs rule.

Conclusions Regarding Air Regulations

To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal fired generating fleet is 100 percent scrubbed for SO_2 and 90 percent controlled for NOx.

Utilization of the Company's NOx and SO_2 allowances can be impacted as these regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

The Company is currently reviewing the sufficiency of its existing pollution control equipment in relation to the requirements described in CSPAR and the Utility HAPs Rule. Based upon an initial review of the final rules, including minor revisions made to CSPAR in October 2011, the Company believes that it will be able to meet these requirements with its existing suite of pollution control equipment and the anticipated allotment of new emission allowances. However, it is possible some minor modifications to the control equipment and additional operating expenses could be required. The Company believes that such additional costs, if necessary, would be recoverable under Indiana Senate Bill 251 referenced above.

Notice of Violation Received
The Company received a notice of violation (NOV) from the EPA pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. Based on the Company's understanding of the New Source Review reform in effect when the equipment was installed, it is the Company's position that its SCR project was exempted from such requirements. At this time the Company is reviewing the potential impact this NOV could have on operating costs. To the extent costs to comply increase, they should be recoverable under Indiana law.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2012. Depending on the final rule and on the Company's facts and circumstances, capital investments could be in the $40 million range if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations would likely qualify as federally mandated regulatory requirements under Indiana Senate Bill 251 referenced above.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules may not be finalized in 2012 given oversight hearings, congressional interest, and other factors.

At this time, the majority of the Company's ash is being beneficially reused. However, the alternatives proposed would require some retrofitting or closure of existing ash ponds. The Company estimates capital expenditures to comply could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase slightly or be impacted by as much as $5 million. Costs for compliance with these regulations would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above.

Climate Change
In April 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress. The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. In April 2012, the USEPA issued its proposed new source performance standards for greenhouse gases applicable to new construction. This proposed rule does not apply to existing sources, such as Vectren's generating facilities. The USEPA has not indicated when it intends to propose standards for existing sources.

Numerous competing federal legislative proposals have also been introduced in recent years that involve carbon, energy efficiency, and renewable energy. Comprehensive energy legislation at the federal level continues to be debated, but there has been little progress to date. The progression of regional initiatives throughout the United States has also slowed.

Impact of Legislative Actions & Other Initiatives is Unknown
If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other greenhouse gases or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants, nonutility coal mining operations, and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control greenhouse gas emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures would be recoverable from customers through Senate Bill 251. Customer rates may also be impacted should decisions be made to reduce the level of sales to municipal and other wholesale customers in order to meet emission targets.

Manufactured Gas Plants
In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds at these sites.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/feasibility study (RI/FS) was completed at one of the sites under an agreed order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plants sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it reasonably expects to incur totaling approximately $41.7 million ($23.2 million at Indiana Gas and $18.5 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. SIGECO filed a declaratory judgment action against its insurance carriers seeking a judgment finding its carriers liable under the policies for coverage of further investigation and any necessary remediation costs that SIGECO may accrue under the VRP program and/or another site subject to a lawsuit that has been settled. In November 2011, the Court ruled on two motions for summary judgment, finding for SIGECO and against certain insurers on indemnification and defense obligations in the policies at issue. SIGECO has settlement agreements with all known insurance carriers and has recorded approximately $15.2 million of expected insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require some level of additional remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of March 31, 2012 and December 31, 2011, respectively, approximately $4.7 million and $6.5 million of accrued, but not yet spent, costs are included in *Other Liabilities* related to both the Indiana Gas and SIGECO sites.

Rate & Regulatory Matters

Vectren South Electric Base Rate Filing
On December 11, 2009, Vectren South filed a request with the IURC to adjust its base electric rates. The requested increase in base rates addressed capital investments, a modified electric rate design that would facilitate a partnership between Vectren South and customers to pursue energy efficiency and conservation, and new energy efficiency programs to complement those currently offered for natural gas customers. The IURC issued an order in the case on April 27, 2011. The order provides for an approximate $28.6 million revenue increase to recover costs associated with approximately $325 million in system upgrades that were completed in the three years leading up to the December 2009 filing and modest increases in maintenance and operating expenses. The approved revenue increase is based on rate base of $1,295.6 million, return on equity of 10.4 percent and an overall rate of return of 7.29 percent. The new rates were effective May 3, 2011. The IURC, in its order, denied the Company's request for implementation of the decoupled rate design, which is discussed further below. Addressing issues raised in the case concerning coal supply contracts and related costs, the IURC found that current coal contracts remain effective and that a prospective review process of future procurement decisions would be initiated.

Coal Procurement Procedures
Vectren South submitted a request for proposal in April 2011 regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, Vectren South has reached an agreement in principle for multi-year purchases with two suppliers, one of which is Vectren Fuels, Inc. Consistent with the IURC direction in the electric rate case, a sub docket proceeding was established to review the Company's prospective coal procurement procedures, and the Company submitted evidence related to its recent request for proposal (RFP) and those coal procurement procedures to the IURC in September 2011. In March 2012, the IURC issued its order in the sub docket. The order concluded that Vectren South's 2011 RFP process resulted in prices at the lowest fuel cost reasonably possible. The IURC will continue to regularly monitor Vectren South's procurement process in future fuel adjustment proceedings.

Vectren South Electric Fuel Cost Reduction
In the spring of 2011, Vectren secured contracts for lower coal costs through a formal bidding process. This lower-priced coal is expected to start being delivered and used at Vectren's power plants by late 2012 to early 2013 and beyond. On December 5, 2011 within the quarterly FAC filing, Vectren South submitted a joint proposal with the OUCC to reduce its fuel costs by accelerating the impact of lower cost coal contracts to be effective after 2012. The agreement to accelerate savings into early 2012 means that the existing 2012 coal costs that are above the new, lower prices will be deferred to a regulatory asset and recovered over a six-year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with a positive impact to customer's rates effective February 1, 2012. Deferrals also include a reduction in the value of the coal inventory at December 31, 2011 of approximately $17.7 million to reflect existing coal inventory at the new, lower price. Deferrals related to coal purchases in 2012 have totaled approximately $9.7 million, bringing the total deferred balance as of March 2012 to $27.4 million.

Vectren South Electric Demand Side Management Program Filing
On August 16, 2010, Vectren South filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed are consistent with a December 9, 2009 order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South service territory that complies with the IURC's energy saving targets. Consistent with the Company's proposal, the order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs; and 4) deferral of lost margin up to $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the order received April 27, 2011. On January 26, 2012, the Company requested approval from the IURC of a recovery mechanism within the existing Demand Side Management Adjustment (DSMA) for lost margins resulting from small customer participation in the Company's DSM programs. The filing included a request for recovery of the $1 million deferred in 2011, and a request for continued deferral of lost margins in 2012 until such point as these lost margins are included in DSMA rates. The evidentiary hearing in this matter is scheduled for June 5, 2012.

Vectren South Electric Dense Pack Filing

On September 14, 2011, Vectren South filed a petition with the IURC seeking recovery of and return on the capital investment in dense pack technology to improve the efficiency of its A.B. Brown Generating Station. This investment is expected to be approximately $32 million over the next two years, of which approximately $22 million has been invested to date. This technology is expected to allow the A.B. Brown units to run at least 5 percent more efficient, thereby burning less fuel, and reducing fuel costs and emissions of pollutants. In the Company's base rate order issued in April 2011, the IURC authorized deferred accounting treatment associated with this investment. Indiana statute also provides for timely recovery of investments, with a return, in instances where the investment increases the efficiency of existing generating plants that are fueled by coal. Several parties have intervened in the case and are requesting that the IURC deny recovery of these project costs outside of a base rate proceeding. A hearing was held by the IURC in February 2012 and proposed orders were submitted by the parties in March 2012. An order on timely recovery is expected later in 2012.

Vectren North Reporting Location Consolidation Proceeding

Vectren North implemented a reporting location consolidation plan in 2011 and converted certain reporting locations into staging areas throughout the Vectren North territory. On May 26, 2011, the International Brotherhood of Electrical Workers Local 1393, United Steel Workers Locals 12213 and 7441 and others (the "Complainants") filed a formal complaint with the IURC claiming that implementation of the consolidation plan by Vectren North endangers public safety and impairs Vectren North's ability to provide adequate, safe and reliable service. The Complainants asked the IURC to require Vectren North to reopen previously consolidated reporting locations and maintain and staff those locations. A hearing in this case was held in February 2012. Complainants submitted a proposed order in March and Vectren North submitted a reply brief and a proposed order in April. The case will be fully briefed as of the first of May and the Company expects the IURC to issue a final order in this matter some time in 2012.

VEDO Continues the Process to Exit the Merchant Function

On August 20, 2008, the PUCO approved the results of an auction selecting qualified wholesale suppliers to provide the gas commodity to the Company for resale to its customers at auction-determined standard pricing. This standard pricing was comprised of the monthly NYMEX settlement price plus a fixed adder. This standard pricing, which was effective from October 1, 2008 through March 31, 2010, was the initial step in exiting the merchant function in the Company's Ohio service territory. The approach eliminated the need for monthly gas cost recovery (GCR) filings and prospective PUCO GCR audits.

The second phase of the exit process began on April 1, 2010. During this phase, the Company no longer sells natural gas directly to customers. Rather, state-certified Competitive Retail Natural Gas Suppliers, that are successful bidders in a similar regulatory-approved auction, sell the gas commodity to specific customers for a 12-month period at auction-determined standard pricing. During the second phase, VEDO conducted its third retail auction on January 31, 2012 to address the 12-month term beginning April 1, 2012. The results of that auction were approved by the PUCO on February 1, 2012. Consistent with current practice, customers continue to receive a single bill for the commodity as well as the delivery component of natural gas service from VEDO.

The PUCO provided for an Exit Transition Cost rider, which allows the Company to recover costs associated with the transition process. Exiting the merchant function has not had a material impact on earnings or financial condition.

Results of Operations of the Nonutility Group

The Nonutility Group operates in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair. Energy Services provides performance contracting and renewable energy services. Coal Mining mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. There are also other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. The Nonutility Group supports the Company's regulated utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services. Nonutility Group earnings for the three ended March 31, 2012 and 2011 follow:

	Three Months Ended March 31,	
(In millions, except per share amounts)	2012	2011
NET INCOME (LOSS)	**$ (4.8)**	**$ (3.4)**
CONTRIBUTION TO VECTREN BASIC EPS	**$ (0.06)**	**$ (0.04)**
NET INCOME (LOSS) ATTRIBUTED TO:		
Infrastructure Services	$ 3.0	$ (2.9)
Energy Services	(1.7)	(1.4)
Coal Mining	(0.3)	1.6
Energy Marketing		
Vectren Source	-	7.1
ProLiance	(5.9)	(7.5)
Other Businesses	0.1	(0.3)

Infrastructure Services

Infrastructure Services provides underground construction and repair services through Miller Pipeline (Miller) and Minnesota Limited, which was acquired on March 31, 2011. Inclusive of holding company costs, results from Infrastructure's operations for the three months ended March 31, 2012 were earnings of $3.0 million, compared to a loss of $2.9 million year to date in 2011. The $5.9 million increase in earnings reflects increased demand across all infrastructure business areas and the acquisition of Minnesota Limited. The warm weather provided for the ability to earn a profit during a period that traditionally operates at a seasonal loss. Revenues in the first quarter of 2012 were $117.5 million. These operations had first quarter revenues in 2011 of $68.3 million, including $21.1 million from Minnesota Limited prior to its acquisition. Construction activity generally is expected to remain strong in 2012 and beyond as utilities and pipeline operators continue to replace their aging natural gas and oil infrastructure and as the need for shale gas and oil infrastructure becomes more prevalent.

<u>Acquisition of Minnesota Limited</u>

On March 31, 2011, the Company purchased Minnesota Limited, Inc., excluding certain assets. Minnesota Limited is a specialty contractor focusing on transmission pipeline construction and maintenance; pump station, compressor station, terminal and refinery construction; gas distribution; and hydrostatic testing. Minnesota Limited is headquartered in Big Lake, Minnesota and the majority of its customers are generally located in the northern Midwest region. The purchase price was approximately $83.4 million and included $14.8 million of net working capital, $34.4 million of property plant and equipment and $39.4 million of intangible assets, including goodwill. This acquisition positions the Company for anticipated growth in demand for gas and oil transmission construction resulting from the need to transport new sources of natural gas and oil found in shale formations and the need to upgrade the nation's aging pipelines.

Energy Services

Energy Services provides energy performance contracting and renewable energy services through Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services' operations contributed a loss of $1.7 million during the first quarter of 2012, compared to a loss of $1.4 million in 2011.

The lower results in 2012 reflect increased operating expenses associated with the continued ramp up of performance contracting personnel. ESG placed its first "build and own" anaerobic digester project into service in the first quarter of 2012. Two additional anaerobic digester projects are under construction and are expected to be placed into service later this year. As of March 31, 2012, performance contracting backlog was $73 million compared to $82 million on December 31, 2011, and $122 million on March 31, 2011. The lower backlog reflects some slowing in the demand for performance contracting projects. However, the national focus on energy conservation, renewable energy, and sustainability are expected to create favorable conditions for long-term growth in this business.

Coal Mining

Coal Mining owns mines that produce and sell coal to the Company's utility operations and to third parties through its wholly owned subsidiary Vectren Fuels, Inc. (Vectren Fuels). Coal Mining, inclusive of holding company costs, operated at loss of $0.3 million during the quarter ended March 31, 2012, compared to earnings of $1.6 million in 2011. Results have been impacted by reduced productivity at the Prosperity mine where a thin coal seam and other unfavorable mining conditions have negatively impacted costs. These increased costs offset very favorable cost per ton results at Oaktown during the period. Revenues decreased as expected due to reduced pricing to customers associated with contracts that had price reopener clauses effective for 2012. Also, sales in the quarter were lower than expected due to the mild weather. Coal sold in the first quarter of 2012 was 1.1 million tons compared to 1.3 million tons in the first quarter of last year. Through March 31, 2012, Coal Mining segment revenues were $58.5 million, a $10.9 million decrease compared to 2011.

Vectren Fuels continues negotiation with a number of customers regarding sales in 2012 and beyond. Coal sales in 2012 are now estimated at 5.6 million tons, with 70 percent sold. The impact of lower prices is expected to result in earnings from Coal Mining operations in 2012 substantially lower than the results in 2011. However, long term, reduced volumes from Central Appalachia and the large number of scrubbers to be installed should drive strong demand for Illinois Basin coal. Changes in market conditions or other circumstances could cause actual results to be materially different from this expectation.

<u>Coal Reserves</u>

As of March 31, 2012 management estimates the Company's total Illinois Basin coal reserves to be approximately 131 million tons. Of this amount, approximately 39 million tons are attributable to a mine that is currently under construction located at the Company's Oaktown mining complex and is expected to open later in 2012. However, Vectren Fuels may continue to adjust this timing as it evaluates the impacts of market conditions. Once this mine is in production, Vectren Fuels underground mines are capable of producing about 7.5 million tons of coal per year.

<u>Mine Safety Information</u>

The Company, through Vectren Fuels, owns coal mines and related assets located in Indiana. The Company has retained independent third party contract mining companies to operate its coal mines. Five Star Mining LLC ("Five Star") is the contract mining company at the Prosperity underground mine and Black Panther Mining LLC ("Black Panther") is the contract mining company at the Oaktown underground mines. While in operation, Vigo-Cypress Creek, LLC was the contract mining company at Cypress Creek surface mine. The contract mining companies are the mine "operator", as that term is used in both the Federal Mine Safety and Health Act of 1977 (the "Mine Act") and the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010. All employees at the coal mines are hired, supervised, and paid by the contract mining companies. As the mine operator, the contract mining companies make all regulatory filings required by the MSHA. In most circumstances, however, the cost of fines and penalties assessed by MSHA are contractually passed through from the contract mining company to Vectren Fuels. The process of settling such claims can take years in certain circumstances. During the quarter ended March 31, 2012, the Company paid approximately $0.1 million related to assessments issued to the mine operators.

On April 30, 2012, Five Star received a citation referred to as an "imminent danger" citation for high levels of methane near one of the roof bolting machines operating in the Prosperity Mine. The machine was idled for approximately two hours while the methane levels were lowered by adjusting airflow near the equipment. Other mining operations continued during this period. No injuries or property damage resulted from the incident.

More detailed information about the Company's mines, including safety-related data, can be found at MSHA's website, www.MSHA.gov. Prosperity operates under the MSHA identification number 1202249; Oaktown 1 operates under the identification number 1202394; Oaktown 2's identification number is 1202418; and Cypress Creek's identification number is 1202178. Mine safety-related data included on the MSHA website is influenced by the size of the mine, the level of activity at the mine, and the mine inspector's judgment, among other factors. These factors can impact the comparability of information from mine to mine and time period to time period. Given the recent incidents at coal mines of other companies, a significant increase in the frequency and scope of MSHA inspections continues. In addition, both houses of Congress are considering new mine safety legislation. The Company is currently assessing the impact new laws and regulations may have on its investments.

Energy Marketing

Vectren Source
Earnings in the first quarter of 2011 from retail energy marketer Vectren Source, which was sold on December 31, 2011, were $7.1 million. Due to the seasonality of the retail gas marketing business and the mild weather, Vectren Source earned $2.8 million for the full year in 2011.

ProLiance
ProLiance, a nonutility energy marketing affiliate of Vectren and Citizens, provides services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance's customers include Vectren's Indiana utilities and Citizens' utilities. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. Consistent with its ownership percentage, Vectren is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member. Therefore, the Company accounts for its investment in ProLiance using the equity method of accounting. On March 17, 2011, an order was received from the IURC providing for ProLiance's continued provision of gas supply services to the Company's Indiana utilities and Citizens Energy Group through March 2016.

Vectren Energy Marketing and Services, Inc (EMS), a wholly owned subsidiary, holds the Company's investment in ProLiance. Within the consolidated entity, EMS is responsible for certain financing costs associated with ProLiance and is also responsible for income taxes and allocated corporate expenses related to the Company's portion of ProLiance's results. During the three ended March 31, 2012 and 2011, EMS' results related to the Company's share of ProLiance's results, which include financing costs income taxes, and other holding company costs, was a loss of approximately $5.9 million, compared to a loss of $7.5 million in 2011.

The reduced quarter over quarter loss primarily reflects the reduction in demand costs for both storage and transportation contracts. Current market have resulted in plentiful natural gas supply and lower and less volatile natural gas prices. Historical basis differences between physical and financial markets and summer and winter prices remain narrow compared to historical trends but have improved somewhat. As an example, the summer-winter strip spread was approximately $0.80 per dekatherm as of March 31, 2012, compared to approximately $0.50 per dekatherm as of March 31, 2011.

Efforts to lower the cost of pipeline and storage demand costs continue. Through negotiations and by dropping some uneconomical contracts as they expire, pipeline transportation and storage costs have been lowered to approximately $55 million for all of 2012, compared to $73 million in 2011. In addition to these reductions, additional opportunities exist to renegotiate or drop remaining contracts, including those with annual demand costs of $18 million that are scheduled to expire through 2015. At March 31, 2012, ProLiance had approximately $149 million of members' equity on its balance sheet, no long-term debt outstanding and borrowings of $45 million on its short-term credit facility. Depressed market conditions continue, but the savings in demand costs and other actions are expected to continue to reduce ProLiance's annual losses in 2012 compared to 2011. Changes in these market conditions or other circumstances could cause actual results to be materially above or below this range.

For the three months ended March 31, 2012 and 2011, the amounts recorded to *Equity in earnings (losses) of unconsolidated affiliates* related to ProLiance's operations totaled a pre-tax loss of $7.6 million and $10.6 million, respectively.

Investment in Liberty Gas Storage
Liberty Gas Storage, LLC (Liberty), a joint venture between a subsidiary of ProLiance and a subsidiary of Sempra Energy (SE), is a development project for salt-cavern natural gas storage facilities. ProLiance is the minority member with a 25 percent interest, which it accounts for using the equity method. The project was expected to include 17 Bcf of capacity in its North site, and an additional capacity of at least 17 Bcf at the South site. The South site also has the potential for further expansion. The Liberty pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra U.S. Gas & Power, and will connect area LNG regasification terminals to an interstate natural gas transmission system and storage facilities.

In late 2008, the project at the North site was halted due to subsurface and well-completion problems, resulting in an impairment charge related to the North site being recorded in 2009. ProLiance's ability to meet the needs of its customers has not been, nor does it expect it to be, impacted. Approximately 12 Bcf of the storage at the South site, which comprises three of the four FERC certified caverns, is fully completed and tested. As a result of the issues encountered at the North site, Liberty requested and the FERC approved the separation of the North site from the South site. As of March 31, 2012 and December 31, 2011, ProLiance's investment in Liberty approximated $34.6 million and $35.1 million, respectively.

Liberty received a Demand for Arbitration from Williams Midstream Natural Gas Liquids, Inc. ("Williams") on February 8, 2011 related to a Sublease Agreement ("Sublease") between Liberty and Williams at the North site. Williams alleges that Liberty was negligent in its attempt to convert certain salt caverns to natural gas storage and thereby damaged the caverns. Williams alleges damages of $56.7 million. Liberty believes that it has complied with all of its obligations to Williams, including properly terminating the Sublease. Liberty intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams.

Other Businesses

Within the Nonutility business segment, there are legacy investments involved in energy-related opportunities and services, real estate, leveraged leases, and other ventures. Other Businesses experienced earnings of $0.1 million during the three months ended March 31, 2012, compared to a loss of $0.3 million in 2011.

Impact of Recently Issued Accounting Guidance

Other Comprehensive Income (OCI)

In 2011, the FASB issued new accounting guidance regarding the presentation of comprehensive income within financial statements. The new guidance will require entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. Under the two-statement approach, the first statement would include components of net income, which is consistent with the income statement format used today, and the second statement would include components of OCI. The guidance does not change the items that must be reported in OCI. The new guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and retrospective application is required. The Company adopted this guidance, as amended for condensed quarterly reporting, for the quarterly reporting period ending March 31, 2012 by reporting comprehensive income as required.

Goodwill Testing

In September 2011, the FASB issued new accounting guidance regarding testing goodwill for impairment. The new guidance will allow the Company an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Using the new guidance, the Company no longer would be required to calculate the fair value of a reporting unit unless the Company determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The Company considered this option during its quarterly reporting period ending March 31, 2012 and concluded the continuation of the use of a quantitative approach is appropriate.

Fair Value Measurement and Disclosure

In May 2011, the FASB issued accounting guidance to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and International Financial Reporting Standards (IFRS). The amendments are not intended to change the application of the current fair value requirements, but to clarify the application of existing requirements. The guidance does change particular principles or requirements for measuring fair value or disclosing information about fair value measurements. To improve consistency, language has been changed to ensure that U.S. GAAP and IFRS fair value measurement and disclosure requirements are described in the same way. The Company adopted this guidance for its quarterly reporting period ending March 31, 2012. The adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

Financial Condition

Within Vectren's consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and Vectren Capital Corp (Vectren Capital) funds short-term and long-term financing needs of the Nonutility Group and corporate operations. Vectren Corporation guarantees Vectren Capital's debt, but does not guarantee Utility Holdings' debt. Vectren Capital's long-term debt, including current maturities, and short-term obligations outstanding at March 31, 2012 approximated $410 million and $125 million, respectively. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. Utility Holdings' long-term debt and short-term obligations outstanding at March 31, 2012 approximated $822 million and $50 million, respectively. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt outstanding at March 31, 2012, was $388 million.

The Company's common stock dividends are primarily funded by utility operations. Nonutility operations have demonstrated profitability and the ability to generate cash flows. These cash flows are primarily reinvested in other nonutility ventures, but are also used to fund a portion of the Company's dividends, and from time to time may be reinvested in utility operations or used for corporate expenses.

The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at March 31, 2012, are A-/A3 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. The credit ratings on SIGECO's secured debt are A/A1. Utility Holdings' commercial paper has a credit rating of A-2/P-2. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 48 percent and 47 percent of long-term capitalization at March 31, 2012 and December 31, 2011, respectively. Long-term capitalization includes long-term debt, including current maturities and debt subject to tender, as well as common shareholders' equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage and interest coverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of March 31, 2012, the Company was in compliance with all debt covenants.

Available Liquidity in Current Credit Conditions

The Company's A-/A3 investment grade credit ratings have allowed it to access the capital markets as needed. The Company anticipates funding future capital expenditures and dividends principally through internally generated funds. Available liquidity has been enhanced by the extension of bonus depreciation legislation. However, the resources required for capital investment remain uncertain for a variety of factors including pending legislative and regulatory initiatives involving gas pipeline modernization; coal mine safety; and expanded EPA regulations for air, water, and fly ash. In addition, the Company may expand its businesses through acquisitions and/or joint venture investment. The timing and amount of such investments depends on a variety of factors, including the availability of acquisition targets and forecasted liquidity. The Company plans to enhance its liquidity as needed by accessing the capital markets. The Company may also consider disposing of certain assets, investments, or businesses to enhance or accelerate internally generated cash flow.

Consolidated Short-Term Borrowing Arrangements

At March 31, 2012, the Company has $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $300 million was available for the Utility Group operations and approximately $125 million was available for the wholly owned Nonutility Group and corporate operations. Both Vectren Capital's and Utility Holdings' short-term credit facilities were renewed in November 2011 and are available through September 2016. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis. Liquidity was increased by the $100 million Utility Holdings debt issuance in February 2012, the net proceeds of which were used to repay short-term indebtedness. Nonutility long-term debt totaling $35 million matured on April 25, 2012 and was replaced with short-term borrowings.

The Company has historically funded the short-term borrowing needs of Utility Holdings' operations through the commercial paper market and expects to use the Utility Holdings short-term borrowing facility in instances where the commercial paper market is not efficient. Following is certain information regarding these short-term borrowing arrangements.

	Utility Group Borrowings		Nonutility Group Borrowings	
(In millions)	2012	2011	2012	2011
Quarter End				
Balance Outstanding	$ 49.7	$ -	$ 125.0	$ 122.3
Weighted Average Interest Rate	0.43%	n/a	1.42%	2.01%
Quarterly Average				
Balance Outstanding	$ 113.4	$ 23.3	$ 76.1	$ 49.7
Weighted Average Interest Rate	0.49%	0.39%	1.42%	2.04%
Maximum Month End Balance Outstanding	$ 214.2	$ 42.5	$ 125.0	$ 122.3

ProLiance Short-Term Borrowing Arrangements

ProLiance, a nonutility energy marketing affiliate of the Company, has separate borrowing capacity available through a syndicated credit facility. This facility was renewed on May 18, 2011 at a $130 million capacity level as adjusted for letters of credit and current inventory and receivable balances. This new one year credit facility, which expires on May 24, 2012, reflects the impact of lower gas prices and resulting lower working capital need. As of March 31, 2012, $45 million in borrowings were outstanding. The facility is not guaranteed by Vectren or Citizens. ProLiance is currently working with financial institutions on replacement of the facility before its expiration with a new asset-based lending facility.

New Share Issues

The Company may periodically issue new common shares to satisfy the dividend reinvestment plan, stock option plan and other employee benefit plan requirements. New issuances added additional liquidity of $1.6 million and $1.7 million in the three months ended March 31, 2012 and 2011, respectively.

Utility Holdings 2012 Debt Issuance

On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements. As of December 31, 2011, the Company had reclassified $100 million of short-term borrowings as long-term debt to reflect that those borrowings were to be refinanced with the proceeds received from the February 1, 2012 long-term debt issuance.

Potential Uses of Liquidity

Pension Funding Obligations

Management currently estimates contributing approximately $15 million to qualified pension plans in 2012. Contributions in 2013 and beyond are dependent on a variety of factors, including the Company's progress toward attaining its long-term goal of being fully funded related to the plans' accrued benefit obligations and the available sources of cash to fund such additional contributions. In the three months ended March 31, 2012, contributions to qualified plans totaled $3.4 million.

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly owned subsidiaries and unconsolidated affiliates. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary and unconsolidated affiliate obligations in order to allow those subsidiaries and affiliates the flexibility to conduct business without posting other forms of collateral. At March 31, 2012, parent level guarantees support a maximum of $25 million of ESG's performance contracting commitments and warranty obligations and $28 million of other project guarantees. The broader scope of ESG's performance contracting obligations, including those not guaranteed by the parent company, are described below. In addition, the parent company has approximately $23 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $19 million represent letters of credit supporting other nonutility operations. Guarantees issued and outstanding on behalf of unconsolidated affiliates approximated $3 million at March 31, 2012. These guarantees relate primarily to arrangements between ProLiance and various natural gas pipeline operators. The Company has not been called upon to satisfy any obligations pursuant to these parental guarantees and has accrued no significant liabilities related to these guarantees.

As a result of the sale of Vectren Source on December 31, 2011, the Company had $56 million of outstanding guarantees related to this formerly wholly owned subsidiary that remained in effect for 90 days after the closing. The buyer's parent will hold the Company harmless if any amounts are required to be paid pursuant to these guarantees and, within the 90 day period, the buyer was required to provide its own guarantees in substitution for the Company guarantees. This arrangement expired on March 31, 2012.

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, including ESG, issue performance bonds or other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and/or support warranty obligations. Based on a history of meeting performance obligations and installed products operating effectively, no significant liability or cost has been recognized during the periods presented.

Specific to ESG, in its role as a general contractor in the performance contracting industry, at March 31, 2012, there are 73 open surety bonds supporting future performance. The average face amount of these bonds is $3.6 million, and the largest obligation has a face amount of $23.7 million. The maximum exposure of these obligations is less than these amounts for several factors, including the level of work already completed. At March 31, 2012, approximately 65 percent of work was completed on projects with open surety bonds. A significant portion of these commitments will be fulfilled within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years.

Other Letters of Credit

As of March 31, 2012, Utility Holdings has letters of credit outstanding in support of two SIGECO tax exempt adjustable rate first mortgage bonds totaling $41.7 million. In the unlikely event the letters of credit were called, the Company could settle with the financial institutions supporting these letters of credit with general assets or by drawing from its credit facility that expires in September 2016. Due to the long-term nature of the credit agreement, such debt is classified as long-term at March 31, 2012.

Planned Capital Expenditures & Investments

Utility capital expenditures are estimated at $190 million for the remainder of 2012. Nonutility capital expenditures and investments are estimated at $105 million for the remainder of 2012.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $168.8 million and $188.4 million for the three months ended March 31, 2012 and 2011, respectively. The reduced cash flow in 2012 reflects lower utility and coal sales in the quarter (and thus higher inventory balances) as impacted by the mild weather. In 2011, the seasonal decline in inventory at Vectren Source resulted in operating cash flow of approximately $22 million. The less cash generated by working capital was partially offset by lower contributions to pension and postretirement plans in 2012.

Financing Cash Flow

Net cash flow required for financing activities was $81.5 million during the three months ended March 31, 2012 compared to requirements of $24.0 million in 2011. Financing activity in 2012 primarily reflects the $100 million debt issuance by Utility Holdings, the payment of dividends, and repayment of short-term borrowings. Less short term borrowings were repaid in in 2011 due primarily to cash needs to acquire Minnesota Limited.

Investing Cash Flow

Cash flow required for investing activities was $81.7 million and $140.3 million during the three months ended March 31, 2012 and 2011, respectively. The prior year investing activities reflect the purchase of Minnesota Limited. The current year period reflects an approximate $30 million increase in cash required for capital expenditures. Mild weather during the first quarter allowed for greater capital expenditures for bare steel/cast iron projects and planned power supply outages. In addition, the increase in capital expenditures reflects additional investment in the Company's coal mines.

Forward-Looking Information

A "safe harbor" for forward-looking statements is provided by the Private Securities Litigation Reform Act of 1995 (Reform Act of 1995). The Reform Act of 1995 was adopted to encourage such forward-looking statements without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Certain matters described in Management's Discussion and Analysis of Results of Operations and Financial Condition are forward-looking statements. Such statements are based on management's beliefs, as well as assumptions made by and information currently available to management. When used in this filing, the words "believe", "anticipate", "endeavor", "estimate", "expect", "objective", "projection", "forecast", "goal", "likely", and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- *Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to fossil fuel costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.*
- *Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornados, terrorist acts or other similar occurrences could adversely affect Vectren's facilities, operations, financial condition and results of operations.*
- *Increased competition in the energy industry, including the effects of industry restructuring and unbundling.*

- *Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under traditional regulation, and the frequency and timing of rate increases.*
- *Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.*
- *Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.*
- *Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity, coal, and other nonutility products and services; impacts on both gas and electric large customers; lower residential and commercial customer counts; higher operating expenses; and further reductions in the value of certain nonutility real estate and other legacy investments.*
- *Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.*
- *Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, interest rate, and warranty risks.*
- *Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.*
- *The performance of projects undertaken by the Company's nonutility businesses and the success of efforts to invest in and develop new opportunities, including but not limited to, the Company's infrastructure, energy services, coal mining, and energy marketing strategies.*
- *Factors affecting coal mining operations including MSHA guidelines and interpretations of those guidelines, as well as additional mine regulations and more frequent and broader inspections that could result from the recent mining incidents at coal mines of other companies; geologic, equipment, and operational risks; the ability to execute and negotiate new sales contracts and resolve contract interpretations; volatile coal market prices and demand; supplier and contract miner performance; the availability of key equipment, contract miners and commodities; availability of transportation; and the ability to access/replace coal reserves.*
- *Factors affecting the Company's investment in ProLiance including natural gas price volatility and basis; the ability to lower fixed contract costs; and availability of credit.*
- *Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.*
- *Risks associated with material business transactions such as mergers, acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.*
- *Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with state and federal laws and interpretations of these laws.*
- *Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, pipeline safety regulations, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.*

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of changes in actual results, changes in assumptions, or other factors affecting such statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company's risk management program includes, among other things, the use of derivatives. The Company may also execute derivative contracts in the normal course of operations while buying and selling commodities to be used in operations and optimizing its generation assets.

The Company has in place a risk management committee that consists of senior management as well as financial and operational management. The committee is actively involved in identifying risks as well as reviewing and authorizing risk mitigation strategies.

These risks are not significantly different from the information set forth in Item 7A Quantitative and Qualitative Disclosures About Market Risk included in the Vectren 2011 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended March 31, 2012, there have been no changes to the Company’s internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of March 31, 2012, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of March 31, 2012, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and

2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II

ITEM 1. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, and rate and regulatory matters. The consolidated condensed financial statements are included in Part 1 Item 1.

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company’s operating results and financial condition, causing them to be materially adversely affected. The Company’s risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren 2011 Form 10-K and are therefore not presented herein.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Periodically, the Company purchases shares from the open market to satisfy share requirements associated with the Company's share-based compensation plans. The following chart contains information regarding open market purchases made by the Company to satisfy share-based compensation requirements during the quarter ended March 31, 2012.

Period	Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares That May Be Purchased Under These Plans
January 1-31	-	$-	-	-
February 1-29	3,784	29.62	-	-
March 1-31	-	-	-	-

ITEM 3. DEFAULTS UPON SENIOR SECURITIES
Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES
Not Applicable

ITEM 5. OTHER INFORMATION
Not Applicable

ITEM 6. EXHIBITS

Exhibits and Certifications

31.1 Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer

31.2 Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer

32 Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002

101 Interactive Data File.

101.INS* XBRL Instance Document

101.SCH* XBRL Taxonomy Extension Schema

101.CAL* XBRL Taxonomy Extension Calculation Linkbase

101.DEF* XBRL Taxonomy Extension Definition Linkbase

101.LAB* XBRL Taxonomy Extension Labels Linkbase

101.PRE* XBRL Taxonomy Extension Presentation Linkbase

* Users of the XBRL-related information in Exhibit 101 to this Quarterly Report on Form 10-Q are advised in accordance with Rule 406T of Regulation S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections. The financial information contained in the XBRL-related documents is "unaudited" and "unreviewed."

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VECTREN CORPORATION
Registrant

May 3, 2012

/s/Jerome A. Benkert, Jr.
Jerome A. Benkert, Jr.
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/M. Susan Hardwick
M. Susan Hardwick
Vice President, Controller and Assistant Treasurer
(Principal Accounting Officer)

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Section 2: EX-31.1 (EXHIBIT 31.1)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

CHIEF EXECUTIVE OFFICER CERTIFICATION

I, Carl L. Chapman, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Vectren Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/ Carl L. Chapman
Carl L. Chapman
Chairman, President, and Chief Executive Officer

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Section 3: EX-31.2 (EXHIBIT 31.2)

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

CHIEF FINANCIAL OFFICER CERTIFICATION

I, Jerome A. Benkert, Jr., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Vectren Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/ Jerome A. Benkert, Jr.
Jerome A. Benkert, Jr.
Executive Vice President and Chief Financial Officer

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Section 4: EX-32 (EXHIBIT 32)

Exhibit 32

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

CERTIFICATION

By signing below, each of the undersigned officers hereby certifies pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his or her knowledge, (i) this report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in this report fairly presents, in all material respects, the financial condition and results of operations of Vectren Corporation.

Signed this 3rd day of May, 2012.

/s/ Jerome A. Benkert, Jr.	/s/ Carl L. Chapman
(Signature of Authorized Officer)	(Signature of Authorized Officer)
Jerome A. Benkert, Jr.	Carl L. Chapman
(Typed Name)	(Typed Name)
Executive Vice President and Chief Financial Officer	Chairman, President, and Chief Executive Officer
(Title)	(Title)

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WGL HOLDINGS INC

FORM 10-Q
(Quarterly Report)

Filed 05/03/12 for the Period Ending 03/31/12

Address	101 CONSTITUTION AVE, N.W. WASHINGTON, DC 20080
Telephone	2026246011
CIK	0001103601
Symbol	WGL
SIC Code	4924 - Natural Gas Distribution
Industry	Natural Gas Utilities
Sector	Utilities
Fiscal Year	09/30

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

☑ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended March 31, 2012

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission File Number	*Exact name of registrant as specified in its charter and principal office address and telephone number*	*State of Incorporation*	*I.R.S. Employer Identification No.*
1-16163	**WGL Holdings, Inc.** 101 Constitution Ave., N.W. Washington, D.C. 20080 (703) 750-2000	Virginia	52-2210912
0-49807	**Washington Gas Light Company** 101 Constitution Ave., N.W. Washington, D.C. 20080 (703) 750-4440	District of Columbia and Virginia	53-0162882

Indicate by check mark whether each registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether each registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

WGL Holdings, Inc.:

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Washington Gas Light Company:

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☑ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

Indicate the number of shares outstanding of each of the issuers' classes of common stock, as of the latest practicable date.

WGL Holdings, Inc. common stock, no par value, outstanding as of April 30, 2012: 51,535,032 shares.

All of the outstanding shares of common stock ($1 par value) of Washington Gas Light Company were held by WGL Holdings, Inc. as of April 30, 2012.

WGL Holdings, Inc.
Washington Gas Light Company

For the Quarter Ended March 31, 2012

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WGL Holdings, Inc.
Washington Gas Light Company

INTRODUCTION

FILING FORMAT

This Quarterly Report on Form 10-Q is a combined report being filed by two separate registrants: WGL Holdings, Inc. (WGL Holdings) and Washington Gas Light Company (Washington Gas). Except where the content clearly indicates otherwise, any reference in the report to "WGL Holdings," "we," "us" or "our" is to the holding company or the consolidated entity of WGL Holdings and all of its subsidiaries, including Washington Gas which is a distinct registrant that is a wholly owned subsidiary of WGL Holdings.

Part I — Financial information in this Quarterly Report on Form 10-Q includes separate financial statements (i.e. balance sheets, statements of income and statements of cash flows) for WGL Holdings and Washington Gas. The Notes to Consolidated Financial Statements are also included and are presented on a combined basis for both WGL Holdings and Washington Gas. The *Management's Discussion and Analysis of Financial Condition and Results of Operations* (Management's Discussion) included under Item 2 is divided into two major sections for WGL Holdings and Washington Gas.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

Certain matters discussed in this report, excluding historical information, include forward-looking statements within the meaning of the *Private Securities Litigation Reform Act of 1995* with respect to the outlook for earnings, revenues and other future financial business performance or strategies and expectations. Forward-looking statements are typically identified by words such as, but not limited to, "estimates," "expects," "anticipates," "intends," "believes," "plans" and similar expressions, or future or conditional verbs such as "will," "should," "would" and "could." Although the registrants, WGL Holdings and Washington Gas, believe such forward-looking statements are based on reasonable assumptions, they cannot give assurance that every objective will be achieved. Forward-looking statements speak only as of today, and the registrants assume no duty to update them. The following factors, among others, could cause actual results to differ materially from forward-looking statements or historical performance:

- the level and rate at which costs and expenses are incurred and the extent to which they are allowed to be recovered from customers through the regulatory process in connection with constructing, operating and maintaining Washington Gas' natural gas distribution system;
- the ability to implement successful approaches to modify the current or future composition of gas delivered to customers or to remediate the effects of the current or future composition of gas delivered to customers, as a result of the introduction of gas from the Dominion Cove Point or the Southern LNG, Inc. Elba Island facility to Washington Gas' natural gas distribution system or changes in the composition of domestic natural gas as a result of liquids processing and new domestic sources of natural gas;
- the availability of natural gas supply and interstate pipeline transportation and storage capacity;
- the ability of natural gas producers, pipeline gatherers and natural gas processors to deliver natural gas into interstate pipelines for delivery by those interstate pipelines to the entrance points of Washington Gas' natural gas distribution system as a result of factors beyond our control;
- changes and developments in economic, competitive, political and regulatory conditions;
- changes in capital and energy commodity market conditions;
- changes in credit ratings of debt securities of WGL Holdings or Washington Gas that may affect access to capital or the cost of debt;
- changes in credit market conditions and creditworthiness of customers and suppliers;
- changes in relevant laws and regulations, including tax, environmental, pipeline integrity and employment laws and regulations;
- legislative, regulatory and judicial mandates or decisions affecting business operations or the timing of recovery of costs and expenses;
- the timing and success of business and product development efforts and technological improvements;
- the pace of deregulation efforts and the availability of other competitive alternatives to our products and services;
- changes in accounting principles;
- new commodity purchase and sales contracts or financial contracts and modifications in the terms of existing contracts that may materially affect fair value calculations under derivative accounting requirements;

- the ability to manage the outsourcing of several business processes;
- acts of nature;
- terrorist activities and
- other uncertainties.

The outcome of negotiations and discussions that the registrants may hold with other parties from time to time regarding utility and energy-related investments and strategic transactions that are both recurring and non-recurring may also affect future performance. All such factors are difficult to predict accurately and are generally beyond the direct control of the registrants. Accordingly, while they believe that the assumptions are reasonable, the registrants cannot ensure that all expectations and objectives will be realized. Readers are urged to use care and consider the risks, uncertainties and other factors that could affect the registrants' business as described in this Quarterly Report on Form 10-Q. All forward-looking statements made in this report rely upon the safe harbor protections provided under the *Private Securities Litigation Reform Act of 1995* .

W GL Holdings, Inc.
Consolidated Balance Sheets (Unaudited)
Part I—Financial Information
Item 1—Financial Statements

(In thousands)	March 31, 2012	September 30, 2011
ASSETS		
Property, Plant and Equipment		
At original cost	**$ 3,664,921**	$ 3,575,973
Accumulated depreciation and amortization	**(1,117,287)**	(1,086,072)
Net property, plant and equipment	**2,547,634**	2,489,901
Current Assets		
Cash and cash equivalents	**97,200**	4,332
Receivables		
Accounts receivable	**347,991**	205,950
Gas costs and other regulatory assets	**33,942**	14,364
Unbilled revenues	**147,115**	94,078
Allowance for doubtful accounts	**(19,263)**	(17,969)
Net receivables	**509,785**	296,423
Materials and supplies—principally at average cost	**26,606**	27,113
Storage gas	**175,688**	290,394
Deferred income taxes	**19,717**	18,816
Other prepayments	**32,471**	63,839
Derivatives	**65,185**	16,248
Other	**14,525**	7,568
Total current assets	**941,177**	724,733
Deferred Charges and Other Assets		
Regulatory assets		
Gas costs	**—**	16,798
Pension and other post-retirement benefits	**453,331**	471,378
Other	**63,466**	69,279
Derivatives	**28,212**	11,721
Other	**31,192**	25,224
Total deferred charges and other assets	**576,201**	594,400
Total Assets	**$ 4,065,012**	$ 3,809,034
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shareholders' equity	**$ 1,292,414**	$ 1,202,715
Washington Gas Light Company preferred stock	**28,173**	28,173
Long-term debt	**585,804**	587,213
Total capitalization	**1,906,391**	1,818,101
Current Liabilities		
Current maturities of long-term debt	**25,071**	77,104
Notes payable	**131,890**	39,421
Accounts payable and other accrued liabilities	**258,818**	279,434
Wages payable	**16,974**	16,949
Accrued interest	**3,673**	3,880
Dividends declared	**20,944**	20,256
Customer deposits and advance payments	**70,577**	78,139
Gas costs and other regulatory liabilities	**35,751**	7,843
Accrued taxes	**69,125**	16,925
Derivatives	**62,284**	31,851
Other	**10,159**	4,938
Total current liabilities	**705,266**	576,740
Deferred Credits		
Unamortized investment tax credits	**16,450**	11,656
Deferred income taxes	**547,803**	527,189
Accrued pensions and benefits	**386,395**	397,460
Asset retirement obligations	**68,497**	66,928
Regulatory liabilities		
Gas costs	**13,457**	—
Accrued asset removal costs	**326,662**	326,154
Other	**16,623**	18,574
Derivatives	**22,290**	15,066
Other	**55,178**	51,166
Total deferred credits	**1,453,355**	1,414,193
Commitments and Contingencies (Note 13)		
Total Capitalization and Liabilities	**$ 4,065,012**	$ 3,809,034

The accompanying notes are an integral part of these statements.

WGL Holdings, Inc.
Consolidated Statements of Income (Unaudited)
Part I—Financial Information
Item 1—Financial Statements (continued)

	Three Months Ended March 31,		Six Months Ended March 31,	
(In thousands, except per share data)	**2012**	2011	**2012**	2011
OPERATING REVENUES				
Utility	**$460,700**	$ 561,297	**$ 824,847**	$ 970,591
Non-utility	**378,744**	455,924	**742,354**	842,504
Total Operating Revenues	**839,444**	1,017,221	**1,567,201**	1,813,095
OPERATING EXPENSES				
Utility cost of gas	**188,475**	286,570	**343,784**	495,190
Non-utility cost of energy-related sales	**356,114**	422,325	**691,976**	751,118
Operation and maintenance	**85,057**	87,531	**166,681**	165,099
Depreciation and amortization	**24,106**	22,647	**48,346**	45,291
General taxes and other assessments	**47,281**	54,203	**84,078**	94,675
Total Operating Expenses	**701,033**	873,276	**1,334,865**	1,551,373
OPERATING INCOME	**138,411**	143,945	**232,336**	261,722
Other Income (Loss)—Net	**1,953**	(1,320)	**2,994**	(432)
Interest Expense				
Interest on long-term debt	**9,430**	10,123	**19,092**	19,897
AFUDC and other, net	**91**	249	**251**	421
Total Interest Expense	**9,521**	10,372	**19,343**	20,318
INCOME BEFORE INCOME TAXES	**130,843**	132,253	**215,987**	240,972
INCOME TAX EXPENSE	**56,334**	52,495	**90,710**	95,652
NET INCOME	**$ 74,509**	$ 79,758	**$ 125,277**	$ 145,320
Dividends on Washington Gas preferred stock	**330**	330	**660**	660
NET INCOME APPLICABLE TO COMMON STOCK	**$ 74,179**	$ 79,428	**$ 124,617**	$ 144,660
AVERAGE COMMON SHARES OUTSTANDING				
Basic	**51,511**	51,143	**51,473**	51,104
Diluted	**51,561**	51,242	**51,546**	51,191
EARNINGS PER AVERAGE COMMON SHARE				
Basic	**$ 1.44**	$ 1.55	**$ 2.42**	$ 2.83
Diluted	**$ 1.44**	$ 1.55	**$ 2.42**	$ 2.83
DIVIDENDS DECLARED PER COMMON SHARE	**$ 0.4000**	$ 0.3875	**$ 0.7875**	$ 0.7650

The accompanying notes are an integral part of these statements.

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WGL Holdings, Inc.
Consolidated Statements of Cash Flows (Unaudited)
Part I—Financial Information
Item 1—Financial Statements (continued)

	Six Months Ended March 31,	
(In thousands)	**2012**	2011
OPERATING ACTIVITIES		
Net income	**$ 125,277**	$ 145,320
ADJUSTMENTS TO RECONCILE NET INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES		
Depreciation and amortization	**48,346**	45,291
Amortization of:		
Other regulatory assets and liabilities—net	**470**	1,832
Debt related costs	**441**	432
Deferred income taxes—net	**25,617**	35,784
Accrued/deferred pension cost	**9,708**	10,051
Compensation expense related to equity awards	**3,203**	1,415
Provision for doubtful accounts	**12,187**	12,352
Other non-cash charges (credits)—net	**3,635**	(1,247)
CHANGES IN ASSETS AND LIABILITIES		
Accounts receivable and unbilled revenues—net	**(205,971)**	(246,326)
Gas costs and other regulatory assets/liabilities—net	**8,330**	54,864
Storage gas	**114,706**	158,718
Other prepayments	**31,368**	34,279
Accounts payable and other accrued liabilities	**(10,108)**	65,249
Wages payable	**25**	585
Customer deposits and advance payments	**(7,562)**	(7,701)
Accrued taxes	**52,200**	49,883
Accrued interest	**(207)**	(28)
Other current assets	**(55,387)**	6,463
Other current liabilities	**35,654**	(26,819)
Deferred gas costs—net	**30,255**	(19,579)
Deferred assets—other	**4,048**	32,621
Deferred liabilities—other	**(18,386)**	(17,027)
Other—net	**76**	1,872
Net Cash Provided by Operating Activities	**207,925**	338,284
FINANCING ACTIVITIES		
Common stock issued	**1,343**	7,105
Long-term debt issued	**—**	75,000
Long-term debt retired	**(52,000)**	(30,000)
Debt issuance costs	**—**	(155)
Notes payable issued (retired)—net	**92,469**	(84,717)
Dividends on common stock and preferred stock	**(37,906)**	(39,234)
Other financing activities—net	**(695)**	(3,692)
Net Cash Provided by (Used in) Financing Activities	**3,211**	(75,693)
INVESTING ACTIVITIES		
Capital expenditures (excluding AFUDC)	**(109,832)**	(74,984)
Investments in non-utility interests	**(11,157)**	(6,452)
Distributions from non-utility interests	**2,721**	—
Net Cash Used in Investing Activities	**(118,268)**	(81,436)
INCREASE IN CASH AND CASH EQUIVALENTS	**92,868**	181,155
Cash and Cash Equivalents at Beginning of Year	**4,332**	8,849
Cash and Cash Equivalents at End of Period	**$ 97,200**	$ 190,004
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION		
Income taxes paid—net	**$ 20,644**	$ 1,509
Interest paid	**$ 19,824**	$ 20,295
SUPPLEMENTAL DISCLOSURES OF NON-CASH INVESTING AND FINANCING ACTIVITIES		
Project debt financing activities—net	**$ (1,393)**	$ 873
Capital expenditures included in accounts payable and other accrued liabilities	**$ 16,492**	$ 9,983

The accompanying notes are an integral part of these statements.

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W ashington Gas Light Company
Balance Sheets (Unaudited)
Part I—Financial Information
Item 1—Financial Statements (continued)

(In thousands)	March 31, 2012	September 30, 2011
ASSETS		
Property, Plant and Equipment		
At original cost	**$ 3,587,695**	$ 3,509,564
Accumulated depreciation and amortization	**(1,090,486)**	(1,060,990)
Net property, plant and equipment	**2,497,209**	2,448,574
Current Assets		
Cash and cash equivalents	**94,214**	1,353
Receivables		
Accounts receivable	**183,678**	81,778
Gas costs and other regulatory assets	**33,942**	14,364
Unbilled revenues	**48,541**	13,888
Allowance for doubtful accounts	**(17,021)**	(15,863)
Net receivables	**249,140**	94,167
Materials and supplies—principally at average cost	**26,560**	27,061
Storage gas	**66,937**	166,054
Deferred income taxes	**18,840**	15,748
Other prepayments	**16,934**	30,601
Receivables from associated companies	**3,771**	21,167
Derivatives	**7,991**	1,311
Other	**6,308**	1,154
Total current assets	**490,695**	358,616
Deferred Charges and Other Assets		
Regulatory assets		
Gas costs	**—**	16,798
Pension and other post-retirement benefits	**450,570**	468,522
Other	**63,465**	69,277
Derivatives	**13,724**	8,739
Other	**6,884**	8,522
Total deferred charges and other assets	**534,643**	571,858
Total Assets	**$ 3,522,547**	$ 3,379,048
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shareholder’s equity	**$ 1,070,555**	$ 990,135
Preferred stock	**28,173**	28,173
Long-term debt	**585,804**	587,213
Total capitalization	**1,684,532**	1,605,521
Current Liabilities		
Current maturities of long-term debt	**25,071**	77,104
Notes payable	**—**	22
Accounts payable and other accrued liabilities	**126,107**	131,055
Wages payable	**16,142**	16,031
Accrued interest	**3,673**	3,880
Dividends declared	**18,884**	18,717
Customer deposits and advance payments	**70,589**	78,139
Gas costs and other regulatory liabilities	**35,751**	7,843
Accrued taxes	**95,213**	22,829
Payables to associated companies	**28,057**	11,792
Derivatives	**5,141**	6,105
Other	**4,971**	5,307
Total current liabilities	**429,599**	378,824
Deferred Credits		
Unamortized investment tax credits	**8,231**	8,677
Deferred income taxes	**538,992**	524,253
Accrued pensions and benefits	**383,765**	394,818
Asset retirement obligations	**67,259**	65,725
Regulatory liabilities		
Gas costs	**13,457**	—
Accrued asset removal costs	**326,662**	326,154
Other	**16,623**	18,574
Derivatives	**4,890**	7,115
Other	**48,537**	49,387
Total deferred credits	**1,408,416**	1,394,703
Commitments and Contingencies (Note 13)		
Total Capitalization and Liabilities	**$ 3,522,547**	$ 3,379,048

The accompanying notes are an integral part of these statements.

Washington Gas Light Company
Statements of Income (Unaudited)
Part I—Financial Information
Item 1—Financial Statements (continued)

	Three Months Ended March 31,		Six Months Ended March 31,	
(In thousands)	**2012**	2011	**2012**	2011
OPERATING REVENUES	**$ 471,057**	$ 569,724	**$841,950**	$988,100
OPERATING EXPENSES				
Utility cost of gas	**197,741**	294,996	**359,558**	512,699
Operation and maintenance	**69,450**	72,980	**136,592**	136,977
Depreciation and amortization	**23,553**	22,128	**47,004**	44,243
General taxes and other assessments	**44,656**	51,273	**78,920**	89,628
Total Operating Expenses	**335,400**	441,377	**622,074**	783,547
OPERATING INCOME	**135,657**	128,347	**219,876**	204,553
Other Income (Loss)—Net	**1,054**	(597)	**1,744**	299
Interest Expense				
Interest on long-term debt	**9,430**	10,123	**19,092**	19,897
AFUDC and other, net	**(21)**	197	**78**	345
Total Interest Expense	**9,409**	10,320	**19,170**	20,242
INCOME BEFORE INCOME TAXES	**127,302**	117,430	**202,450**	184,610
INCOME TAX EXPENSE	**54,830**	46,427	**85,472**	72,830
NET INCOME	**$ 72,472**	$ 71,003	**$116,978**	$111,780
Dividends on Washington Gas preferred stock	**330**	330	**660**	660
NET INCOME APPLICABLE TO COMMON STOCK	**$ 72,142**	$ 70,673	**$116,318**	$111,120

The accompanying notes are an integral part of these statements.

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Washington Gas Light Company
Statements of Cash Flows (Unaudited)
Part I—Financial Information
Item 1—Financial Statements (continued)

(In thousands)	Six Months Ended March 31, 2012	2011
OPERATING ACTIVITIES		
Net income	**$ 116,978**	$ 111,780
ADJUSTMENTS TO RECONCILE NET INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES		
Depreciation and amortization	**47,004**	44,243
Amortization of:		
Other regulatory assets and liabilities—net	**470**	(1,970)
Debt related costs	**440**	432
Deferred income taxes—net	**17,334**	22,256
Accrued/deferred pension cost	**9,631**	9,979
Compensation expense related to equity awards	**2,545**	1,351
Provision for doubtful accounts	**9,839**	10,022
Other non-cash charges (credits)—net	**(755)**	(1,971)
CHANGES IN ASSETS AND LIABILITIES		
Accounts receivable, unbilled revenues and receivables from associated companies—net	**(127,838)**	(191,656)
Gas costs and other regulatory assets/liabilities—net	**8,330**	54,864
Storage gas	**99,117**	111,865
Other prepayments	**13,667**	26,859
Accounts payable and other accrued liabilities, including payables to associated companies	**17,208**	45,302
Wages payable	**111**	780
Customer deposits and advance payments	**(7,550)**	(5,701)
Accrued taxes	**72,384**	37,956
Accrued interest	**(207)**	(28)
Other current assets	**(11,333)**	6,797
Other current liabilities	**(1,300)**	(9,200)
Deferred gas costs—net	**30,255**	(19,579)
Deferred assets—other	**13,324**	32,519
Deferred liabilities—other	**(34,185)**	(1,999)
Other—net	**226**	1,806
Net Cash Provided by Operating Activities	**275,695**	286,707
FINANCING ACTIVITIES		
Long-term debt issued	**—**	75,000
Long-term debt retired	**(52,000)**	(30,000)
Debt issuance costs	**—**	(155)
Notes payable issued (retired)—net	**(22)**	(43,419)
Dividends on common stock and preferred stock	**(37,459)**	(36,941)
Other financing activities—net	**879**	(574)
Net Cash Used in Financing Activities	**(88,602)**	(36,089)
INVESTING ACTIVITIES		
Capital expenditures (excluding AFUDC)	**(94,232)**	(69,938)
Net Cash Used in Investing Activities	**(94,232)**	(69,938)
INCREASE IN CASH AND CASH EQUIVALENTS	**92,861**	180,680
Cash and Cash Equivalents at Beginning of Year	**1,353**	4,390
Cash and Cash Equivalents at End of Period	**$ 94,214**	$ 185,070
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION		
Income taxes paid—net	**$ 10,303**	$ —
Interest paid	**$ 19,651**	$ 20,219
SUPPLEMENTAL DISCLOSURES OF NON-CASH INVESTING AND FINANCING ACTIVITIES		
Project debt financing activities—net	**$ (1,393)**	$ 873
Capital expenditures included in accounts payable and other accrued liabilities	**$ 15,995**	$ 9,983

The accompanying notes are an integral part of these statements.

WGL Holdings, Inc.
Washington Gas Light Company
Part I—Financial Information
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Notes to Consolidated Financial Statements (Unaudited)

NOTE 1. ACCOUNTING POLICIES

Basis of Presentation

WGL Holdings, Inc. (WGL Holdings) is a holding company that owns all of the shares of common stock of Washington Gas Light Company (Washington Gas), a regulated natural gas utility, and all of the shares of common stock of Washington Gas Resources Corporation (Washington Gas Resources), Hampshire Gas Company (Hampshire) and Crab Run Gas Company. Washington Gas Resources owns all of the shares of common stock of four non-utility subsidiaries that include Washington Gas Energy Services, Inc. (WGEServices), Washington Gas Energy Systems, Inc. (WGESystems), Capitol Energy Ventures Corp. (CEV) and WGSW, Inc. (WGSW). Except where the content clearly indicates otherwise, "WGL Holdings," "we," "us" or "our" refers to the holding company or the consolidated entity of WGL Holdings and all of its subsidiaries. Unless otherwise noted, these notes apply equally to WGL Holdings and Washington Gas.

The interim consolidated financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Therefore, certain financial information and note disclosures accompanying annual financial statements prepared in accordance with generally accepted accounting principles in the United States of America (GAAP) are omitted in this interim report. The interim consolidated financial statements and accompanying notes should be read in conjunction with the combined Annual Report on Form 10-K for WGL Holdings and Washington Gas for the fiscal year ended September 30, 2011. Due to the seasonal nature of our businesses, the results of operations for the periods presented in this report are not necessarily indicative of actual results for the full fiscal years ending September 30, 2012 and 2011 of either WGL Holdings or Washington Gas.

The accompanying unaudited financial statements for WGL Holdings and Washington Gas reflect all normal recurring adjustments that are necessary, in our opinion, to present fairly the results of operations in accordance with GAAP. Certain prior period amounts in the accompanying balance sheets have been reclassified to conform to the current period presentation.

For a complete description of our accounting policies, refer to Note 1 of the Notes to Consolidated Financial Statements of the combined Annual Report on Form 10-K for WGL Holdings and Washington Gas for the fiscal year ended September 30, 2011.

Storage Gas Valuation Methods

For Washington Gas and WGEServices, storage gas inventory is stated at the lower-of-cost or market as determined using the first-in, first-out method. For CEV, storage gas inventory is stated at the lower-of-cost or market using the weighted average cost method. For the three and six months ended March 31, 2012, WGL Holdings recorded, as a reduction to net income, lower-of-cost or market adjustments of $21.8 million and $31.7 million, respectively, and recorded no significant lower-of-cost or market adjustments for the three or six month periods ended March 31, 2011. There were no significant lower-of-cost or market adjustments recorded by Washington Gas during the three and six month periods ended March 31, 2012 and 2011.

Accounting Standards Adopted in the Current Fiscal Year

Fair Value. In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* . ASU 2011-04 amends ASC Topic 820 to include a consistent definition of the term "fair value" and set forth common requirements for measuring fair value and disclosing information about fair value measurements in financial statements. ASU 2011-04 was effective for us beginning January 1, 2012. The adoption of this standard did not have a material effect on our financial statements. *Refer to Note 10 – Fair Value Measurements* for the required disclosure under this standard.

Fair Value. In January 2010, the FASB issued ASU 2010-06, *Improving Disclosures about Fair Value Measurements* . ASU 2010-06 amends ASC Topic 820 to require the following additional disclosures regarding fair value measurements: *(i)* the amounts of transfers between Level 1 and Level 2 of the fair value hierarchy; *(ii)* reasons for any transfers in or out of Level 3 of the fair value hierarchy and *(iii)* the inclusion of information about purchases, sales, issuances and settlements in the reconciliation of recurring Level 3 measurements. ASU 2010-06 also amends ASC Topic 820 to clarify existing disclosure requirements, requiring fair value disclosures by class of assets and liabilities rather than by major category and the disclosure of valuation techniques and inputs used to determine the fair value of Level 2 and Level 3 assets and liabilities. With the exception of disclosures relating to purchases, sales, issuances and settlements of recurring Level 3 measurements, ASU 2010-06 was effective for us on January 1, 2010. The remaining disclosure requirements were effective for us on October 1, 2011. The adoption of this standard did not have a material effect on our financial statements. *Refer to Note 10 – Fair Value Measurements* for the required disclosure under this standard.

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Newly Issued Accounting Standards

Balance Sheet Offsetting. In December 2011, the FASB issued ASU 2011-11, *Disclosures about Offsetting Assets and Liabilities* . This standard amends the disclosure requirements on offsetting in ASC Topic 210 by requiring enhanced disclosures about financial instruments and derivative instruments that are either (*i*) offset in accordance with existing guidance or (*ii*) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. ASU 2011-11 will be effective for us on October 1, 2013. We do not expect the adoption of this standard to have a material effect on our financial statements.

Comprehensive Income. In June 2011, the FASB issued ASU 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income* . ASU 2011-05 is intended to improve financial reporting by requiring companies to present items of net income in either one continuous statement, or in two separate but consecutive statements of net income and other comprehensive income. The new guidance removes the current presentation options in ASC Topic 220. The requirements of ASU 2011-05 do not change which components of comprehensive income are recognized in net income or other comprehensive income, nor does the update change the computation of earnings per share (EPS). ASU 2011-05 will be effective for us on October 1, 2012. We do not expect the adoption of this standard to have a material effect on our financial statements.

NOTE 2. ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES

The tables below provide details for the amounts included in "Accounts payable and other accrued liabilities" on the balance sheets for both WGL Holdings and Washington Gas.

WGL Holdings, Inc.

(In millions)	**March 31, 2012**	September 30, 2011
Accounts payable—trade	**$ 208.5**	$ 210.4
Employee benefits and payroll accruals	**18.5**	26.5
Derivatives and other accrued liabilities	**31.8**	42.5
Total	**$ 258.8**	$ 279.4

Washington Gas Light Company

(In millions)	**March 31, 2012**	September 30, 2011
Accounts payable—trade	**$ 91.1**	$ 103.0
Employee benefits and payroll accruals	**17.2**	23.7
Derivatives and other accrued liabilities	**17.8**	4.4
Total	**$ 126.1**	$ 131.1

NOTE 3. SHORT-TERM DEBT

WGL Holdings and Washington Gas satisfy their short-term financing requirements through the sale of commercial paper or through bank borrowings. Due to the seasonal nature of our businesses, short-term financing requirements can vary significantly during the year. We maintain revolving credit agreements to support our outstanding commercial paper and to permit short-term borrowing flexibility. Our policy is to maintain bank credit facilities in an amount equal to or greater than our expected maximum commercial paper position. The following is a summary of our committed credit available at March 31, 2012 and September 30, 2011.

Committed Credit Available (In millions)

As of March 31, 2012	**WGL Holdings**	**Washington Gas**	**Total Consolidated**
Committed credit agreements			
Unsecured revolving credit facility, expires August 3, 2012 [(a)]	**$ 400.0**	**$ 300.0**	**$ 700.0**
Less: Commercial Paper	**(131.9)**	**—**	**(131.9)**
Net committed credit available	**$ 268.1**	**$ 300.0**	**$ 568.1**

As of September 30, 2011	WGL Holdings	Washington Gas	Total Consolidated
Committed credit agreements			
Unsecured revolving credit facility, expires August 3, 2012 [(a)]	$ 400.0	$ 300.0	$ 700.0
Less: Commercial Paper	(39.4)	—	(39.4)
Net committed credit available	$ 360.6	$ 300.0	$ 660.6

[(a)] *Both WGL Holdings and Washington Gas have the right to request extensions with the banks' approval. WGL Holdings' revolving credit facility permits it to borrow an additional $50 million, with the banks' approval, for a total of $450 million. Washington Gas' revolving credit facility permits it to borrow an additional $100 million, with the banks' approval, for a total of $400 million.*

At March 31, 2012 and September 30, 2011, WGL Holdings and its subsidiaries had outstanding notes payable in the form of commercial paper from revolving credit facilities of $131.9 million and $39.4 million, respectively, at a weighted average interest rate of 0.31% and 0.20%, respectively. At March 31, 2012 and September 30, 2011, there were no outstanding bank loans from WGL Holdings' or Washington Gas' revolving credit facilities.

NOTE 4. LONG-TERM DEBT

UNSECURED NOTES

Washington Gas issues unsecured Medium-Term Notes (MTNs) and private placement notes with individual terms regarding interest rates, maturities and call or put options. These notes can have maturity dates of one or more years from the date of issuance.

On October 17 and 19, 2011, Washington Gas retired $7.0 million of 6.05% MTN's and $20.0 million of 6.00% MTN's respectively. In addition, Washington Gas also retired $25.0 million of 6.00% MTN's on February 27, 2012.

At March 31, 2012, Washington Gas had the capacity, under a shelf registration to issue up to $375.0 million of additional MTNs. At March 31, 2012 and September 30, 2011, outstanding MTNs and private placement notes were $608.0 million and $660.0 million, respectively. At both March 31, 2012 and September 30, 2011, the weighted average interest rate on all MTNs and private placement notes was 5.91%.

WGL Holdings, Inc.
Washington Gas Light Company
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NOTE 5. COMMON SHAREHOLDERS' EQUITY

The tables below reflect the changes in "Common shareholders' equity" for WGL Holdings and Washington Gas for the six months ended March 31, 2012.

WGL Holdings, Inc.
Components of Common Shareholders' Equity

(In thousands)	Common Stock Amount	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net of Taxes	Total
Balance at September 30, 2011	$ 557,594	$ 7,731	$648,052	$ (10,662)	$1,202,715
Net income	—	—	125,277	—	125,277
Post-retirement benefits adjustment, net of taxes	—	—	—	189	189
Comprehensive income					125,466
Dividends reinvestment	3,136				3,136
Stock-based compensation	3,687	(1,361)	—	—	2,326
Dividends declared:					
Common stock	—	—	(40,569)	—	(40,569)
Preferred stock			(660)		(660)
Balance at March 31, 2012	**$ 564,417**	**$ 6,370**	**$732,100**	**$ (10,473)**	**$1,292,414**

Washington Gas Light Company
Components of Common Shareholder's Equity

(In thousands)	Common Stock Amount	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net of Taxes	Total
Balance at September 30, 2011	$ 46,479	$473,099	$481,219	$ (10,662)	$ 990,135
Net income	—	—	116,978	—	116,978
Post-retirement benefits adjustment, net of taxes	—	—	—	189	189
Comprehensive income					117,167
Stock-based compensation	—	880	—	—	880
Dividends declared:					
Common stock	—	—	(36,967)	—	(36,967)
Preferred stock	—	—	(660)	—	(660)
Balance at March 31, 2012	**$ 46,479**	**$473,979**	**$560,570**	**$ (10,473)**	**$1,070,555**

WGL Holdings had 51,532,467 and 51,365,337 shares issued of common stock at March 31, 2012 and September 30, 2011, respectively. Washington Gas had 46,479,536 shares issued of common stock at both March 31, 2012 and September 30, 2011.

WGL Holdings, Inc.
Washington Gas Light Company
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NOTE 6. COMPREHENSIVE INCOME

The tables below reflect the components of comprehensive income (loss) for the three and six months ended March 31, 2012 and 2011 for WGL Holdings and Washington Gas. Items that are excluded from net income (loss) and charged directly to common shareholders' equity are recorded in other comprehensive income (loss), net of taxes. The amount of accumulated other comprehensive income (loss), net of taxes is included in common shareholders' equity (refer to Note 5— *Common Shareholders' Equity*).

WGL Holdings, Inc.
Components of Comprehensive Income

	Three Months Ended March 31,		Six Months Ended March 31,	
(In thousands)	**2012**	2011	**2012**	2011
Net income	**$ 74,509**	$ 79,758	**$125,277**	$145,320
Other comprehensive income, net of taxes [(a)]	**198**	146	**189**	275
Comprehensive income	**$ 74,707**	$ 79,904	**$125,466**	$145,595

(a) Amounts relate to post-retirement benefits.

Washington Gas Light Company
Components of Comprehensive Income

	Three Months Ended March 31,		Six Months Ended March 31,	
(In thousands)	**2012**	2011	**2012**	2011
Net income	**$ 72,472**	$ 71,003	**$116,978**	$111,780
Other comprehensive income, net of taxes [(a)]	**198**	146	**189**	275
Comprehensive income	**$ 72,670**	$ 71,149	**$117,167**	$112,055

(a) Amounts relate to post-retirement benefits.

NOTE 7. EARNINGS PER SHARE

Basic EPS is computed by dividing net income by the weighted average number of common shares outstanding during the reported period. Diluted EPS assumes the issuance of common shares pursuant to stock-based compensation plans at the beginning of the applicable period unless the effect of such issuance would be anti-dilutive. The following table reflects the computation of our basic and diluted EPS for the three and six months ended March 31, 2012 and 2011.

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Washington Gas Light Company
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Basic and Diluted EPS

(In thousands, except per share data)	Net Income Applicable to Common Stock	Shares	Per Share Amount
Three Months Ended March 31, 2012			
Basic EPS	**$ 74,179**	**51,511**	**$ 1.44**
Stock-based compensation plans	**—**	**50**	
Diluted EPS	**$ 74,179**	**51,561**	**$ 1.44**
Three Months Ended March 31, 2011			
Basic EPS	$ 79,428	51,143	$ 1.55
Stock-based compensation plans	—	99	
Diluted EPS	$ 79,428	51,242	$ 1.55
Six Months Ended March 31, 2012			
Basic EPS	**$ 124,617**	**51,473**	**$ 2.42**
Stock-based compensation plans	**—**	**73**	
Diluted EPS	**$ 124,617**	**51,546**	**$ 2.42**
Six Months Ended March 31, 2011			
Basic EPS	$ 144,660	51,104	$ 2.83
Stock-based compensation plans	—	87	
Diluted EPS	$ 144,660	51,191	$ 2.83

There were no anti-dilutive shares for the three and six months ended March 31, 2012 or 2011.

NOTE 8. INCOME TAXES

As of March 31, 2012, our uncertain tax positions were approximately $19.7 million primarily due to the change in tax accounting for repairs. If the amounts of unrecognized tax benefits are eventually realized, it would not materially impact the effective tax rate. It is reasonably possible that the amount of the unrecognized tax benefit with respect to Washington Gas's uncertain tax positions will significantly increase or decrease in the next 12 months due to the on-going audit of Washington Gas by the IRS with respect to the tax year related to its change in accounting method for repairs. At this time an estimate of the range of reasonably possible outcomes cannot be determined.

Under the provision of FIN 48 (now part of ASC Topic 740, Income Taxes),Washington Gas recognizes any accrued interest associated with uncertain tax positions in interest expense and recognizes any accrued penalties associated with uncertain tax positions in other expenses in the statements of income. During each of the quarters ended March 31, 2012 and 2011, we accrued $0.2 million in expense for interest on uncertain tax positions. At March 31, 2012 and September 30, 2011, we had a total accrual of $1.4 million and $0.9 million, respectively, of interest related to uncertain tax positions included in other deferred credits in the accompanying balance sheets.

NOTE 9. DERIVATIVE AND WEATHER-RELATED INSTRUMENTS

DERIVATIVE INSTRUMENTS

Regulated Utility Operations

Washington Gas enters into contracts related to the sale and purchase of natural gas that qualify as derivative instruments and are accounted for under ASC Topic 815. These derivative instruments are recorded at fair value on our balance sheet and Washington Gas does not designate any derivatives as hedges under ASC Topic 815. Washington Gas' derivative instruments relate to: *(i)* Washington Gas' asset optimization program; *(ii)* managing price risk associated with the purchase of gas to serve utility customers and *(iii)* managing interest rate risk.

Asset Optimization. Washington Gas optimizes the value of its long-term natural gas transportation and storage capacity resources during periods when these resources are not being used to physically serve utility customers. Specifically, Washington Gas utilizes its transportation capacity assets to benefit from favorable natural gas prices between different geographic locations and its storage capacity assets to benefit from favorable natural gas prices between different time periods. As part of this asset optimization program, Washington Gas enters into physical and financial derivative transactions in the form of forward, swap and option contracts to lock-in operating margins that Washington Gas will ultimately realize. The derivatives used under this program are subject to mark-to-market accounting treatment.

Regulatory sharing mechanisms allow the profit from these transactions to be shared between Washington Gas' shareholders and customers; therefore, any changes in fair value are recorded through earnings, or as regulatory assets or liabilities to the extent that gains and losses associated with these derivative instruments will be included in the rates charged to customers when they are realized. Valuation changes for the portion of net profits to be retained for shareholders may cause significant period-to-period volatility in earnings from unrealized gains and losses. This volatility does not change the locked-in operating margins that Washington Gas will ultimately realize from these transactions.

All physically and financially settled contracts under our asset optimization program are reported on a net basis in the statements of income in "Utility cost of gas". Total net margins recorded to "Utility cost of gas" after sharing and management fees associated with all asset optimization transactions for the three months ended March 31, 2012 was a gain of $4.8 million including an unrealized gain of $1.1 million. During the three months ended March 31, 2011 we recorded a gain of $2.9 million including an unrealized derivative loss of $4.7 million. Total net margins recorded for the six months ended March 31, 2012 was a gain of $8.5 million including an unrealized gain of $1.5 million. During the six months ended March 31, 2011 we recorded gains of $1.1 million including an unrealized derivative loss of $14.5 million.

Managing Price Risk. To manage price risk associated with acquiring natural gas supply for utility customers, Washington Gas enters into forward contracts, option contracts, financial swap contracts and other contracts, as authorized by its regulators. These instruments are accounted for as derivative instruments. Any gains and losses associated with these derivatives are recorded as regulatory liabilities or assets, respectively, to reflect the rate treatment for these economic hedging activities.

Managing Interest-Rate Risk . Washington Gas utilizes derivative instruments that are designed to minimize the risk of interest-rate volatility associated with planned issuances of debt securities. Any gains and losses associated with these types of derivatives are recorded as regulatory liabilities or assets, respectively, and amortized in accordance with regulatory requirements, which is typically over the life of the newly issued debt.

Non-Utility Operations

WGEServices enters into certain derivative contracts as part of managing the price risk associated with the sale and purchase of natural gas and electricity. CEV enters into derivative contracts for the purpose of optimizing its storage and transportation capacity as well as managing the transportation and storage assets on behalf of third parties. Derivative instruments are recorded at fair value on our consolidated balance sheets. Neither WGEServices nor CEV designate these derivatives as hedges under ASC Topic 815; therefore, changes in the fair value of these derivative instruments are reflected in the earnings of our non-utility operations and may cause significant period-to-period volatility in earnings.

Consolidated Operations

Reflected in the tables below is information for WGL Holdings as well as Washington Gas. The information for WGL Holdings includes derivative instruments for both utility and non-utility operations.

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At March 31, 2012 and September 30, 2011, respectively, the absolute notional amounts of our derivatives are as follows:

Absolute Notional Amounts
of Open Positions on Derivative Instruments

As of March 31, 2012	**Notional Amounts**	
Derivative transactions	**WGL Holdings**	**Washington Gas**
Natural Gas *(In millions of therms)*		
Asset optimization	**2,994.1**	**2,270.8**
Retail sales	**133.8**	**—**
Other risk-management activities	**604.6**	**256.5**
Electricity *(In kWhs)*		
Retail sales	**3,054.8**	**—**
Other risk-management activities	**15,317.7**	**—**

Absolute Notional Amounts
of Open Positions on Derivative Instruments

As of September 30, 2011	**Notional Amounts**	
Derivative transactions	**WGL Holdings**	**Washington Gas**
Natural Gas *(In millions of therms)*		
Asset optimization	1,538.6	1,221.7
Retail sales	131.4	—
Other risk-management activities	656.2	392.0
Electricity *(In kWhs)*		
Retail sales	606.5	—
Other risk-management activities	17,085.1	—

The following tables present the balance sheet classification for all derivative instruments as of March 31, 2012 and September 30, 2011.

WGL Holdings, Inc.
Balance Sheet Classification of Derivative Instruments

(In millions)				
As of March 31, 2012	**Derivative Assets**	**Derivative Liabilities**	**Netting of Collateral**	**Total**
Current Assets — Derivatives	**$ 88.9**	**$ (23.7)**	**$ —**	**$ 65.2**
Deferred Charges and Other Assets — Derivatives	**69.1**	**(40.9)**	**—**	**28.2**
Accounts payable and other accrued liabilities	**3.6**	**—**	**—**	**3.6**
Current Liabilities — Derivatives	**9.7**	**(75.6)**	**3.6**	**(62.3)**
Deferred Credits — Derivatives	**3.7**	**(28.4)**	**2.4**	**(22.3)**
Total	**$ 175.0**	**$ (168.6)**	**$ 6.0**	**$ 12.4**
As of September 30, 2011				
Current Assets — Derivatives	$ 26.2	$ (10.1)	$ 0.1	$ 16.2
Deferred Charges and Other Assets — Derivatives	39.1	(27.4)	—	11.7
Accounts payable and other accrued liabilities	7.1	(1.8)	—	5.3
Current Liabilities — Derivatives	9.6	(41.1)	(0.4)	(31.9)
Deferred Credits — Derivatives	5.1	(23.2)	3.0	(15.1)
Total	$ 87.1	$ (103.6)	$ 2.7	$(13.8)

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Washington Gas Light Company
Balance Sheet Classification of Derivative Instruments

(In millions)							
As of March 31, 2012		**Derivative Assets**		**Derivative Liabilities**		**Netting of Collateral**	**Total**
Current Assets — Derivatives	**$**	**23.2**	**$**	**(15.2)**	**$**	**—**	**$ 8.0**
Deferred Charges and Other Assets — Derivatives		**54.1**		**(40.4)**		**—**	**13.7**
Current Liabilities — Derivatives		**7.8**		**(12.9)**		**—**	**(5.1)**
Deferred Credits — Derivatives		**3.6**		**(8.5)**		**—**	**(4.9)**
Total	**$**	**88.7**	**$**	**(77.0)**	**$**	**—**	**$11.7**
As of September 30, 2011							
Current Assets — Derivatives	$	5.8	$	(4.5)	$	—	$ 1.3
Deferred Charges and Other Assets — Derivatives		36.1		(27.4)		—	8.7
Current Liabilities — Derivatives		9.0		(15.1)		—	(6.1)
Deferred Credits — Derivatives		4.5		(11.6)		—	(7.1)
Total	$	55.4	$	(58.6)	$	—	$ (3.2)

The following table presents all gains and losses associated with derivative instruments for the three and six months ended March 31, 2012 and 2011.

Gains and Losses on Derivative Instruments

(In millions)	**WGL Holdings, Inc.**		**Washington Gas Light Company**	
Three Months Ended March 31,	**2012**	2011	**2012**	2011
Recorded to income				
Operating revenues—non-utility	**$ 32.4**	$ (0.8)	**$ —**	$ —
Utility cost of gas	**5.0**	(5.8)	**5.0**	(5.8)
Non-utility cost of energy-related sales	**(20.0)**	2.4	**—**	—
Recorded to regulatory assets				
Gas costs	**14.2**	(5.6)	**14.2**	(5.6)
Total	**$ 31.6**	$ (9.8)	**$ 19.2**	$ (11.4)

Gains and Losses on Derivative Instruments

(In millions)	**WGL Holdings, Inc.**		**Washington Gas Light Company**	
Six Months Ended March 31,	**2012**	2011	**2012**	2011
Recorded to income				
Operating revenues—non-utility	**$ 65.6**	$ (7.6)	**$ —**	$ —
Utility cost of gas	**7.6**	(10.9)	**7.6**	(10.9)
Non-utility cost of energy-related sales	**(62.3)**	27.7	**—**	—
Recorded to regulatory assets				
Gas costs	**25.6**	(20.9)	**25.6**	(20.9)
Other	**—**	6.2	**—**	6.2
Total	**$ 36.5**	$ (5.5)	**$ 33.2**	$ (25.6)

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Collateral

In accordance with ASC 815, WGL Holdings offsets the fair value of derivative instruments against the right to reclaim or obligation to return collateral for derivative instruments executed under the same master netting arrangement. At March 31, 2012, Washington Gas, WGEServices and CEV posted $4.4 million, $13.4 million and $0.3 million, respectively, of collateral deposits with counterparties that were not offset against open and settled derivative contracts. At September 30, 2011, Washington Gas, WGEServices and CEV posted $9.7 million, $15.8 million and $9.7 million, respectively, of collateral deposits with counterparties that were not offset against open and settled derivative contracts. In addition, at September 30, 2011, Washington Gas held $3.5 million of cash collateral representing an obligation to counterparties that was not offset against open and settled derivative contracts. Any collateral posted that is not offset against open and settled derivative contracts is included in “Other prepayments” in the accompanying balance sheet. Collateral received and not offset against open and settled derivative contracts is included in “Customer deposits and advance payments” in the accompanying balance sheet.

Certain of Washington Gas’ derivative instruments contain contract provisions that require collateral to be posted if the credit rating of Washington Gas’ debt falls below certain levels. Certain of WGEServices’ and CEV’s derivative instruments contain contract provisions that require collateral to be posted if the credit rating of WGL Holdings falls below certain levels or if counterparty exposure to WGEServices or CEV exceeds a certain level. Due to counterparty exposure levels, at March 31, 2012, WGEServices did not post collateral related to its derivative liabilities that contained credit-related contingent features. At September 30, 2011, WGEServices’ posted $0.1 million of collateral related to these aforementioned derivative liabilities. Washington Gas and CEV were not required to post any collateral related to its derivative liabilities that contained credit-related contingent features at March 31, 2012 and September 30, 2011. The following table shows the aggregate fair value of all derivative instruments with credit-related contingent features that are in a liability position, as well as the maximum amount of collateral that would be required to be posted related to the net fair value of our derivative instruments if the most intrusive credit-risk-related contingent features underlying these agreements were triggered on March 31, 2012 and September 30, 2011, respectively.

Potential Collateral Requirements for Derivative Liabilities
with Credit-risk-Contingent Features

(In millions)	WGL Holdings	Washington Gas
March 31, 2012		
Derivative liabilities with credit-risk-contingent features	**$ 133.9**	**$ 65.5**
Maximum potential collateral requirements	**65.3**	**0.1**
September 30, 2011		
Derivative liabilities with credit-risk-contingent features	$ 75.1	$ 45.1
Maximum potential collateral requirements	30.1	1.8

Washington Gas, WGEServices and CEV do not enter into derivative contracts for speculative purposes.

Concentration of Credit Risk

Washington Gas, WGEServices and CEV are exposed to credit risk associated with agreements with wholesale counterparties that are accounted for as derivative instruments. We have credit policies in place that are designed to mitigate credit risk associated with wholesale counterparties through a requirement for credit enhancements including, but not limited to, letters of credit, parent guarantees and cash collateral when deemed necessary. For certain counterparties or their guarantors that meet this policy’s credit worthiness criteria, Washington Gas, WGEServices and CEV grant unsecured credit which is continuously monitored. Additionally, our agreements with wholesale counterparties contain netting provisions that allow Washington Gas, WGEServices and CEV to offset the receivable and payable exposure related to each counterparty. At March 31, 2012, four counterparties individually represented over 10% of Washington Gas’ credit exposure to wholesale derivative counterparties for a total credit risk of $11.2 million; four counterparties individually represented over 10% of WGEServices’ credit exposure to wholesale counterparties for a total credit risk of $0.2 million and three counterparties individually represented over 10% of CEV’s credit exposure to wholesale counterparties for a total credit risk of $6.1 million.

WEATHER-RELATED INSTRUMENTS

During the three months ended March 31, 2012 and 2011, Washington Gas used Heating Degree Day (HDD) weather derivatives to manage its financial exposure to variations from normal weather in the District of Columbia. Under these contracts, Washington Gas purchased protection against net revenue shortfalls due to warmer-than-normal weather and sold to the counterparty the right to receive the benefit when weather is colder than normal. Washington Gas chose to value all weather derivatives at fair value.

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Gains and losses associated with Washington Gas' weather-related instruments are recorded to "Operation and maintenance" expense. During the three months ended March 31, 2012 and 2011, Washington Gas recorded a pre-tax net fair value gain of $4.9 million and a pre-tax net fair value loss of $1.1 million, respectively, related to weather derivatives. During the six months ended March 31, 2012 and 2011, Washington Gas recorded a pre-tax net fair value gain of $7.7 million and a pre-tax net fair value loss of $2.6 million, respectively, related to weather derivatives.

WGEServices utilizes weather-related derivatives for managing the financial effects of weather risks. These derivatives cover a portion of WGEServices' estimated revenue or energy-related cost exposure to variations in heating or cooling degree days. These contracts provide for payment to WGEServices of a fixed-dollar amount for every degree day over or under specific levels during the calculation period depending upon the type of contract executed. For the three and six months ended March 31, 2012, WGEServices recorded pre-tax gains of $8.8 million and $15.1 million, respectively. For the three and six months ended March 31, 2011, WGEServices recorded pre-tax losses of $2.3 million and $4.2 million, respectively, related to these derivatives.

NOTE 10. FAIR VALUE MEASUREMENTS

We measure the fair value of our financial assets and liabilities in accordance with ASC Topic 820. These financial assets and liabilities primarily consist of *(i)* derivatives recorded on our balance sheet under ASC Topic 815, *(ii)* weather derivatives and *(iii)* long-term debt outstanding that is required to be disclosed at fair value. Under ASC Topic 820, fair value is defined as the exit price, representing the amount that would be received in the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. To value our financial instruments, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about credit risk (both our own credit risk and the counterparty's credit risk) and the risks inherent in the inputs to our valuation technique, the income approach.

We enter into derivative contracts in the over-the-counter (OTC) wholesale and retail markets. These markets are the principal markets for the respective wholesale and retail contracts. We have determined that all of our existing counterparties and others who have participated in energy transactions at our delivery points are the relevant market participants. These participants have access to the same market data as WGL Holdings. We value our derivative contracts based on an "in-exchange" premise and valuations are generally based on pricing service data or indicative broker quotes depending on the market location. We measure the net credit exposure at a counterparty level where the right to set-off exists. The net exposure is determined using the mark-to-market exposure adjusted for collateral, letters of credit and parent guarantees. We use published default rates from Standard & Poor's Ratings Services and Moody's Investors Service as inputs for the determination of credit adjustments.

ASC Topic 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. The three levels of the fair value hierarchy under ASC Topic 820 are described below:

Level 1. Level 1 of the fair value hierarchy consists of assets or liabilities that are valued using observable inputs based upon unadjusted quoted prices in active markets for identical assets or liabilities at the reporting date. Level 1 assets and liabilities primarily include exchange traded derivatives and securities. At March 31, 2012, we do not have any financial assets or liabilities in this category.

Level 2. Level 2 of the fair value hierarchy consists of assets or liabilities that are valued using directly or indirectly observable inputs that are corroborated with market data or based on exchange traded market data. Level 2 includes fair values based on industry-standard valuation techniques that consider various assumptions including: *(i)* quoted forward prices, including the use of mid-market pricing within a bid/ask spread; *(ii)* discount rates; *(iii)* implied volatility and *(iv)* other economic factors. Substantially all of these assumptions are observable throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the relevant market. At March 31, 2012, Level 2 financial assets and liabilities included non-exchange traded energy-related derivatives such as financial swaps and options and physical forward contracts for deliveries at active market locations.

Level 3. Level 3 of the fair value hierarchy consists of assets or liabilities that are valued using significant unobservable inputs at the reporting date. These unobservable assumptions reflect our assumptions about estimates that market participants would use in pricing the asset or liability, including natural gas basis prices, annualized volatilities of natural gas prices, and electricity congestion prices. A significant change to any one of these inputs in isolation could result in a significant upward or downward fluctuation in the fair value measurement. These inputs may be used with industry standard valuation methodologies that result in our best estimate of fair value for the assets or liabilities at the reporting date.

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The Company has a Risk Analysis and Mitigation (RA&M) Group that determines the valuation policies and procedures. The RA&M Group reports to the WGL Holdings Treasurer. In accordance with WGL Holdings' Valuation Policy, we may utilize a variety of valuation methodologies to fair value Level 3 derivative contracts including internally developed valuation inputs and pricing models. In addition, the prices used in our valuations are corroborated using multiple pricing sources, and we periodically conduct assessments to determine whether each valuation model is still appropriate for its intended purpose. Any use of non-industry standard models used in valuations are documented and approved by the WGL Holdings Treasurer. The RA&M Group also evaluates changes in fair value measurements on a daily basis.

At March 31, 2012, Level 3 derivative assets and liabilities included: *(i)* physical contracts valued with significant basis adjustments to observable market data when delivery is to inactive market locations; *(ii)* long-dated positions where observable pricing is not available over the life of the contract; *(iii)* contracts valued using historical volatility assumptions and *(iv)* valuations using indicative broker quotes for inactive market locations. Additionally, at March 31, 2012 and September 30, 2011, Level 3 financial instruments included weather derivatives that were valued using unadjusted valuations provided by third parties and derived from significant unobservable market data.

The following tables set forth financial instruments recorded at fair value as of March 31, 2012 and September 30, 2011, respectively. A financial instrument's classification within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

WGL Holdings, Inc.
Fair Value Measurements Under the Fair Value Hierarchy

(In millions)	Level 1	Level 2	Level 3	Total
At March 31, 2012				
Assets				
Natural gas related derivatives	**$ —**	**$ 97.0**	**$ 46.4**	**$ 143.4**
Electricity related derivatives	**—**	**—**	**31.6**	**31.6**
Weather derivatives	**—**	**—**	**6.3**	**6.3**
Total Assets	**$ —**	**$ 97.0**	**$ 84.3**	**$ 181.3**
Liabilities				
Natural gas related derivatives	**$ —**	**$ (63.8)**	**$ (47.4)**	**$(111.2)**
Electricity related derivatives	**—**	**(21.4)**	**(36.0)**	**(57.4)**
Total Liabilities	**$ —**	**$ (85.2)**	**$ (83.4)**	**$(168.6)**
At September 30, 2011				
Assets				
Natural gas related derivatives	$ —	$ 38.0	$ 29.3	$ 67.3
Electricity related derivatives	—	0.2	19.6	19.8
Weather derivatives	—	—	1.3	1.3
Total Assets	$ —	$ 38.2	$ 50.2	$ 88.4
Liabilities				
Natural gas related derivatives	$ —	$ (40.2)	$ (33.2)	$ (73.4)
Electricity related derivatives	—	(3.8)	(26.4)	(30.2)
Weather derivatives	—	—	(2.7)	(2.7)
Total Liabilities	$ —	$ (44.0)	$ (62.3)	$(106.3)

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Washington Gas Light Company
Fair Value Measurements Under the Fair Value Hierarchy

(In millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
At March 31, 2012				
Assets				
Natural gas related derivatives	**$ —**	**$ 49.3**	**$ 39.4**	**$ 88.7**
Weather derivatives	**—**	**—**	**6.3**	**6.3**
Total Assets	**$ —**	**$ 49.3**	**$ 45.7**	**$ 95.0**
Liabilities				
Natural gas related derivatives	**$ —**	**$ (33.0)**	**$ (44.0)**	**$(77.0)**
Total Liabilities	**$ —**	**$ (33.0)**	**$ (44.0)**	**$(77.0)**
At September 30, 2011				
Assets				
Natural gas related derivatives	$ —	$ 28.7	$ 26.7	$ 55.4
Weather derivatives	—	—	1.3	1.3
Total Assets	$ —	$ 28.7	$ 28.0	$ 56.7
Liabilities				
Natural gas related derivatives	$ —	$ (27.0)	$ (31.6)	$(58.6)
Weather derivatives	—	—	(2.7)	(2.7)
Total Liabilities	$ —	$ (27.0)	$ (34.3)	$(61.3)

The following table includes quantitative information about the significant unobservable inputs used in the fair value measurement of our Level 3 financial instruments and the respective fair values of the net derivative asset and liability positions, by contract type, as of March 31, 2012.

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Quantitative Information about Level 3 Fair Value Measurements

(In millions)	Fair Value March 31, 2012	Valuation Techniques	Unobservable Inputs	Range
WGL Holdings				
Natural gas related derivatives	**($1.0)**	Discounted Cash Flow	Natural Gas Basis Price *(per DTH)*	($0.348) - $2.3575
		Option Model	Natural Gas Basis Price *(per DTH)*	$0.041 - $0.898
			Annualized Volatility of Spot Market Natural Gas	37.8% - 307.1%
Electricity related derivatives	**($4.4)**	Discounted Cash Flow	Electricity Congestion Price *(per MWH)*	($3.807) - $66.35
		Load-Shaping Option Model	Electricity Congestion Price *(per MWH)*	$28.50 - $57.983
Washington Gas				
Natural gas related derivatives	**($4.6)**	Discounted Cash Flow	Natural Gas Basis Price *(per DTH)*	($0.348) - $2.3575
		Option Model	Natural Gas Basis Price *(per DTH)*	$0.041 - $0.601
			Annualized Volatility of Spot Market Natural Gas	37.8% - 307.1%

The following tables are a summary of the changes in the fair value of our derivative instruments that are measured at net fair value on a recurring basis in accordance with ASC Topic 820 using significant Level 3 inputs during the three and six months ended March 31, 2012 and 2011, respectively.

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WGL Holdings
Reconciliation of Fair Value Measurements Using Significant Level 3 Inputs

(In millions)	Natural Gas Related Derivatives	Electricity Related Derivatives	Weather Related Derivatives	Total
Three Months Ended March 31, 2012				
Balance at January 1, 2012	$ (3.4)	$ (7.0)	$ 1.4	$ (9.0)
Realized and unrealized gains (losses)				
Recorded to income	10.4	(12.3)	4.9	3.0
Recorded to regulatory assets — gas costs	4.6	—	—	4.6
Transfers out of Level 3	(7.3)	—	—	(7.3)
Purchases	—	(0.1)	—	(0.1)
Settlements	(5.3)	15.0	—	9.7
Balance at March 31, 2012	$ (1.0)	$(4.4)	$6.3	$ 0.9

Washington Gas
Reconciliation of Fair Value Measurements Using Significant Level 3 Inputs

(In millions)	Natural Gas Related Derivatives	Electricity Related Derivatives	Weather Related Derivatives	Total
Three Months Ended March 31, 2012				
Balance at January 1, 2012	$ (1.6)	$ —	$ 1.4	$ (0.2)
Realized and unrealized gains (losses)				
Recorded to income	1.4	—	4.9	6.3
Recorded to regulatory assets — gas costs	4.6	—	—	4.6
Transfers out of Level 3	(7.3)	—	—	(7.3)
Settlements	(1.7)	—	—	(1.7)
Balance at March 31, 2012	$ (4.6)	$ —	$ 6.3	$ 1.7

Reconciliation of Fair Value Measurements Using Significant Level 3 Inputs

(In millions)	WGL Holdings	Washington Gas
Three Months Ended March 31, 2011		
Balance at January 1, 2011	$ (16.1)	$ (3.0)
Realized and unrealized gains (losses)		
Recorded to income	(3.8)	(2.3)
Recorded to regulatory assets — gas costs	(2.3)	(2.3)
Transfers in and/or out of Level 3	(6.7)	(7.8)
Purchases and settlements, net	1.8	(0.6)
Balance at March 31, 2011	$ (27.1)	$ (16.0)

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Washington Gas Light Company
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WGL Holdings
Reconciliation of Fair Value Measurements Using Significant Level 3 Inputs

(In millions)	Natural Gas Related Derivatives	Electricity Related Derivatives	Weather Related Derivatives	Total
Six Months Ended March 31, 2012				
Balance at October 1, 2011	$ (3.9)	$ (6.8)	$ (1.4)	$(12.1)
Realized and unrealized gains (losses)				
Recorded to income	9.8	(23.4)	7.7	(5.9)
Recorded to regulatory assets — gas costs	7.4	—	—	7.4
Transfers out of Level 3	(9.4)	—	—	(9.4)
Purchases		0.8	—	0.8
Settlements	(4.9)	25.0	—	20.1
Balance at March 31, 2012	$ (1.0)	$ (4.4)	$ 6.3	$ 0.9

Washington Gas
Reconciliation of Fair Value Measurements Using Significant Level 3 Inputs

(In millions)	Natural Gas Related Derivatives	Electricity Related Derivatives	Weather Related Derivatives	Total
Six Months Ended March 31, 2012				
Balance at October 1, 2011	$ (4.9)	$ —	$ (1.4)	$ (6.3)
Realized and unrealized gains (losses)				
Recorded to income	1.5	—	7.7	9.2
Recorded to regulatory assets — gas costs	7.4	—	—	7.4
Transfers out of Level 3	(8.1)	—	—	(8.1)
Settlements	(0.5)	—	—	(0.5)
Balance at March 31, 2012	$ (4.6)	$ —	$ 6.3	$ 1.7

Reconciliation of Fair Value Measurements Using Significant Level 3 Inputs

(In millions)	WGL Holdings	Washington Gas
Six Months Ended March 31, 2011		
Balance at October 1, 2010	$ (9.6)	$ 15.2
Realized and unrealized gains (losses)		
Recorded to income	(8.1)	(7.9)
Recorded to regulatory assets — gas costs	(14.9)	(14.9)
Transfers in and/or out of Level 3	(6.7)	(7.8)
Purchases and settlements, net	12.2	(0.6)
Balance at March 31, 2011	$ (27.1)	$ (16.0)

Transfers between different levels of the fair value hierarchy may occur based on the level of observable inputs used to value the instruments from period to period. It is our policy to show both transfers into and out of the different levels of the fair value hierarchy at the fair value as of the beginning of the reporting period. For WGL Holdings and Washington Gas net derivative assets transferred out of Level 3 during the three and six months ended March 31, 2012, reflected an increase in observable market inputs used to value natural gas derivatives for Washington Gas and CEV.

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The table below sets forth the line items on the Statements of Income to which amounts are recorded for the three and six months ended March 31, 2012 and 2011, respectively, related to fair value measurements using significant Level 3 inputs.

WGL Holdings
Realized and Unrealized Gains (Losses) Recorded to Income for Level 3 Measurements

Three Months Ended	**March 31, 2012**				March 31, 2011
(In millions)	**Natural Gas Related Derivatives**	**Electricity Related Derivatives**	**Weather Related Derivatives**	**Total**	Total
Operating revenues — non-utility	**$ 2.3**	**$ 1.3**	**$ —**	**$ 3.6**	$ (3.2)
Utility cost of gas	**1.4**	**—**	**—**	**1.4**	(1.0)
Non-utility cost of energy — related sales	**6.7**	**(13.6)**	**—**	**(6.9)**	1.7
Operation and maintenance expense	**—**	**—**	**4.9**	**4.9**	(1.3)
Total	**$ 10.4**	**$ (12.3)**	**$ 4.9**	**$ 3.0**	$ (3.8)

Washington Gas
Realized and Unrealized Gains (Losses) Recorded to Income for Level 3 Measurements

Three Months Ended	**March 31, 2012**				March 31, 2011
(In millions)	**Natural Gas Related Derivatives**	**Electricity Related Derivatives**	**Weather Related Derivatives**	**Total**	Total
Utility cost of gas	**$ 1.4**	**$ —**	**$ —**	**$ 1.4**	$ (1.0)
Operation and maintenance expense	**—**	**—**	**4.9**	**4.9**	(1.3)
Total	**$ 1.4**	**$ —**	**$ 4.9**	**$ 6.3**	$ (2.3)

WGL Holdings
Realized and Unrealized Gains (Losses) Recorded to Income for Level 3 Measurements

Six Months Ended	**March 31, 2012**				March 31, 2011
(In millions)	**Natural Gas Related Derivatives**	**Electricity Related Derivatives**	**Weather Related Derivatives**	**Total**	Total
Operating revenues—non-utility	**$ 5.5**	**$ 7.8**	**$ —**	**$ 13.3**	$ (8.5)
Utility cost of gas	**1.5**	**—**	**—**	**1.5**	(5.1)
Non-utility cost of energy — related sales	**2.8**	**(31.2)**	**—**	**(28.4)**	8.3
Operation and maintenance expense	**—**	**—**	**7.7**	**7.7**	(2.8)
Total	**$ 9.8**	**$ (23.4)**	**$ 7.7**	**$ (5.9)**	$ (8.1)

Washington Gas
Realized and Unrealized Gains (Losses) Recorded to Income for Level 3 Measurements

Six Months Ended	**March 31, 2012**				March 31, 2011
(In millions)	**Natural Gas Related Derivatives**	**Electricity Related Derivatives**	**Weather Related Derivatives**	**Total**	Total
Utility cost of gas	**$ 1.5**	**$ —**	**$ —**	**$ 1.5**	$ (5.1)
Operation and maintenance expense	**—**	**—**	**7.7**	**7.7**	(2.8)
Total	**$ 1.5**	**$ —**	**$ 7.7**	**$ 9.2**	$ (7.9)

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Unrealized gains (losses) for the three and six months ended March 31, 2012 and 2011, attributable to derivative assets and liabilities measured using significant Level 3 inputs were recorded as follows, respectively:

WGL Holdings
Unrealized Gains (Losses) Recorded for Level 3 Measurements

Three Months Ended	**March 31, 2012**				March 31, 2011
(In millions)	**Natural Gas Related Derivatives**	**Electricity Related Derivatives**	**Weather Related Derivatives**	**Total**	Total
Recorded to income					
Operating revenues — non-utility	**$ 2.6**	**$ 5.5**	**$ —**	**$ 8.1**	$ (0.3)
Utility cost of gas	**0.7**	**—**	**—**	**0.7**	(3.1)
Non-utility cost of energy — related sales	**6.7**	**2.3**	**—**	**9.0**	0.2
Operation and maintenance expense	**—**	**—**	**4.9**	**4.9**	(1.1)
Recorded to regulatory assets — gas costs	**2.3**	**—**	**—**	**2.3**	(3.7)
Total	**$ 12.3**	**$ 7.8**	**$ 4.9**	**$25.0**	$ (8.0)

Washington Gas
Unrealized Gains (Losses) Recorded for Level 3 Measurements

Three Months Ended	**March 31, 2012**				March 31, 2011
(In millions)	**Natural Gas Related Derivatives**	**Electricity Related Derivatives**	**Weather Related Derivatives**	**Total**	Total
Recorded to income					
Utility cost of gas	**$ 0.7**	**$ —**	**$ —**	**$ 0.7**	$ (3.1)
Operation and maintenance expense	**—**	**—**	**4.9**	**4.9**	(1.1)
Recorded to regulatory assets — gas costs	**2.3**	**—**	**—**	**2.3**	(3.7)
Total	**$ 3.0**	**$ —**	**$ 4.9**	**$ 7.9**	$ (7.9)

WGL Holdings
Unrealized Gains (Losses) Recorded for Level 3 Measurements

Six Months Ended	**March 31, 2012**				March 31, 2011
(In millions)	**Natural Gas Related Derivatives**	**Electricity Related Derivatives**	**Weather Related Derivatives**	**Total**	Total
Recorded to income					
Operating revenues — non-utility	**$ 6.0**	**$ 15.4**	**$ —**	**$21.4**	$ 1.3
Utility cost of gas	**0.4**	**—**	**—**	**0.4**	(2.8)
Non-utility cost of energy-related sales	**(1.3)**	**(6.0)**	**—**	**(7.3)**	4.4
Operation and maintenance expense	**—**	**—**	**7.7**	**7.7**	(2.8)
Recorded to regulatory assets — gas costs	**2.1**	**—**	**—**	**2.1**	(15.1)
Total	**$ 7.2**	**$ 9.4**	**$ 7.7**	**$24.3**	**$ (15.0)**

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Washington Gas
Unrealized Gains (Losses) Recorded for Level 3 Measurements

Six Months Ended	**March 31, 2012**				March 31, 2011
(In millions)	**Natural Gas Related Derivatives**	**Electricity Related Derivatives**	**Weather Related Derivatives**	**Total**	Total
Recorded to income					
Utility cost of gas	**$ 0.4**	**$ —**	**$ —**	**$ 0.4**	$ (2.8)
Operation and maintenance expense	**—**	**—**	**7.7**	**7.7**	(2.8)
Recorded to regulatory assets — gas costs	**2.1**	**—**	**—**	**2.1**	(15.1)
Total	**$ 2.5**	**$ —**	**$ 7.7**	**$10.2**	$ (20.7)

The following table presents the carrying amounts and estimated fair values of our financial instruments at March 31, 2012 and September 30, 2011. The carrying amount of current assets and current liabilities approximates fair value because of the short-term maturity of these instruments, and therefore are not shown in the table below.

Fair Value of Financial Instruments

	March 31, 2012		September 30, 2011	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term debt [(a)]	**$ 585.8**	**$ 712.7**	$ 587.2	$ 720.9

[(a)] *Excludes current maturities and unamortized discounts.*

Washington Gas' long-term debt is not actively traded. The fair value of long-term debt was estimated based on the quoted market prices of the U.S. Treasury issues having a similar term to maturity, adjusted for Washington Gas' credit quality. Our long-term debt fair value measurement is classified as Level 3 as defined in ASC Topic 820.

NOTE 11. OPERATING SEGMENT REPORTING

We identify and report on operating segments under the "management approach." Our chief operating decision maker is our Chief Executive Officer. Operating segments comprise revenue-generating components of an enterprise for which we produce separate financial information internally that we regularly use to make operating decisions and assess performance.

During the first quarter of fiscal year 2012, we made certain changes to our operating segment reporting to reflect the recent growth of our non-utility business activities and the impact of those activities on our financial performance. All of our commercial energy assets and operating activities are now reported within a newly-defined operating segment entitled commercial energy systems. All activities of WGESystems are included in the commercial energy systems segment. WGESystems had previously been reported in the design build energy systems segment, which is now being eliminated as an operating segment. In addition, we have transferred all commercial solar projects, previously reported under retail energy-marketing into the commercial energy systems segment. In the future, commercial solar projects, energy efficiency projects and combined heat and power projects, which we own and manage directly, will be reported as commercial energy systems. We have also established wholesale energy solutions as a new segment that contains the activities of CEV, our non-utility asset optimization business, which we began in fiscal year 2010 and previously included in our segment reporting as part of "other activities". Prior period operating segment information has been recast to conform to current quarter presentation.

These changes improve visibility into our operations and better align our reporting with current management accountability. Our four segments are summarized below.

- **Regulated Utility –** The regulated utility segment is our core business. It comprises Washington Gas and Hampshire and provides regulated gas distribution services (including the sale and delivery of natural gas) to customers and natural gas transportation services to an unaffiliated natural gas distribution company in West Virginia under a Federal Energy Regulatory Commission (FERC) approved interstate transportation service operating agreement.
- **Retail Energy-Marketing –** The retail energy-marketing segment consists of WGEServices, which sells natural gas and electricity directly to retail customers and in competition with regulated utilities and unregulated gas and electricity marketers.
- **Commercial Energy Systems –** The commercial energy systems segment consists of WGESystems and provides design-build energy efficient and sustainable solutions including commercial solar, energy efficiency and combined heat and power projects to government and commercial clients.
- **Wholesale Energy Solutions –** The wholesale energy solutions segment comprises CEV, which engages in acquiring, managing and optimizing natural gas storage and transportation assets.

Activities and transactions that are not significant enough on a stand-alone basis to warrant treatment as an operating segment, and that do not fit into one of our four operating segments, are aggregated as "Other Activities" and included as part of non-utility operations as presented below in the Operating Segment Financial Information. These activities include the operations of WGSW, a holding company formed to invest in alternative energy power generating facilities, and administrative costs associated with WGL Holdings and Washington Gas Resources.

While net income or loss applicable to common stock is the primary criterion for measuring a segment's performance, we also evaluate our operating segments based on other relevant factors, such as penetration into their respective markets and return on equity.

The following tables present operating segment information for the three and six months ended March 31, 2012 and 2011.

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Operating Segment Financial Information

		Non-Utility Operations					
(In thousands)	Regulated Utility	Retail Energy-Marketing	Commercial Energy Systems	Wholesale Energy Solutions	Other Activities	Eliminations	Consolidated
Three Months Ended March 31, 2012							
Operating Revenues [a]	**$ 471,057**	**$ 368,381**	**$ 14,170**	**$ (3,807)**	**$ —**	**$ (10,357)**	**$ 839,444**
Operating Expenses:							
Cost of Energy-Related Sales	**197,741**	**343,936**	**12,178**	**—**	**—**	**(9,266)**	**544,589**
Operation	**54,687**	**14,159**	**900**	**449**	**1,524**	**(681)**	**71,038**
Maintenance	**14,019**	**—**	**—**	**—**	**—**	**—**	**14,019**
Depreciation and Amortization	**23,846**	**174**	**468**	**28**	**—**	**(410)**	**24,106**
General Taxes and Other Assessments:							
Revenue Taxes	**28,728**	**1,465**	**2**	**—**	**—**	**—**	**30,195**
Other	**16,020**	**937**	**59**	**52**	**18**	**—**	**17,086**
Total Operating Expenses	**$ 335,041**	**$ 360,671**	**$ 13,607**	**$ 529**	**$ 1,542**	**$ (10,357)**	**$ 701,033**
Operating Income (Loss)	**136,016**	**7,710**	**563**	**(4,336)**	**(1,542)**	**—**	**138,411**
Other Income (Expense)-Net	**1,047**	**9**	**(2)**	**—**	**937**	**(38)**	**1,953**
Interest Expense	**9,409**	**29**	**—**	**—**	**121**	**(38)**	**9,521**
Dividends on Washington Gas Preferred Stock	**330**	**—**	**—**	**—**	**—**	**—**	**330**
Income Tax Expense (Benefit)	**54,973**	**3,225**	**32**	**(1,614)**	**(282)**	**—**	**56,334**
Net Income (Loss) Applicable to Common Stock	**$ 72,351**	**$ 4,465**	**$ 529**	**$ (2,722)**	**$ (444)**	**$ —**	**$ 74,179**
Total Assets	**$3,537,030**	**$ 374,084**	**$ 39,069**	**$ 145,629**	**$ 183,413**	**$ (214,213)**	**$ 4,065,012**
Capital Expenditures	**$ 47,228**	**$ 380**	**$ 2,733**	**$ 101**	**$ —**	**$ —**	**$ 50,442**
Equity Method Investments	**$ —**	**$ —**	**$ —**	**$ —**	**$ 16,559**	**$ —**	**$ 16,559**
Three Months Ended March 31, 2011							
Operating Revenues [a]	$ 569,724	$ 447,706	$ 7,803	$ 415	$ —	$ (8,427)	$ 1,017,221
Operating Expenses:							
Cost of Energy—Related Sales	294,996	415,662	6,664	—	—	(8,427)	708,895
Operation	60,298	12,957	996	199	1,103	—	75,553
Maintenance	11,978	—	—	—	—	—	11,978
Depreciation and Amortization	22,419	163	65	—	—	—	22,647
General Taxes and Other Assessments:							
Revenue Taxes	34,339	1,611	—	—	—	—	35,950
Other	17,032	1,143	65	4	9	—	18,253
Total Operating Expenses	441,062	431,536	7,790	203	1,112	(8,427)	873,276
Operating Income (Loss)	128,662	16,170	13	212	(1,112)	—	143,945
Other Income-Net	(616)	10	3	—	(668)	(49)	(1,320)
Interest Expense	10,320	39	—	—	62	(49)	10,372
Dividends on Washington Gas Preferred Stock	330	—	—	—	—	—	330
Income Tax Expense (Benefit)	46,553	6,467	34	84	(643)	—	52,495
Net Income (Loss) Applicable to Common Stock	$ 70,843	$ 9,674	$ (18)	$ 128	$ (1,199)	$ —	$ 79,428
Total Assets at March 31, 2011	$3,508,410	$ 325,193	$ 18,193	$ 52,678	$ 65,098	$ (99,873)	$ 3,869,699
Capital Expenditures	$ 37,817	$ 4,669	$ 3	$ —	$ —	$	$ 42,489
Equity Method Investments	$ —	$ —	$ —	$ —	$ 1,302	$ —	$ 1,302

[a] *Operating revenues are reported gross of revenue taxes. Revenue taxes of both the regulated utility and the retail energy-marketing segments include gross receipt taxes. Revenue taxes of the regulated utility segment also include PSC fees, franchise fees and energy taxes. Operating revenue amounts in the "Eliminations" column represent total intersegment revenues associated with sales from the regulated utility segment to the retail energy-marketing segment.*

WGL Holdings, Inc.
Washington Gas Light Company
Part I—Financial Information
Item 2—Management's Discussion and Analysis of
Financial Condition and Results of Operations (continued)

Operating Segment Financial Information

		Non-Utility Operations					
(In thousands)	Regulated Utility	Retail Energy-Marketing	Commercial Energy Systems	Wholesale Energy Solutions	Other Activities	Eliminations	Consolidated
Six Months Ended March 31, 2012							
Operating Revenues [(a)]	**$ 841,950**	**$ 704,840**	**$ 32,550**	**$ 4,964**	**$ —**	**$ (17,103)**	**$ 1,567,201**
Operating Expenses:							
Cost of Energy-Related Sales	**359,558**	**663,396**	**28,580**	**—**	**—**	**(15,774)**	**1,035,760**
Operation	**108,342**	**27,362**	**1,869**	**799**	**2,375**	**(829)**	**139,918**
Maintenance	**26,763**	**—**	**—**	**—**	**—**	**—**	**26,763**
Depreciation and Amortization	**47,590**	**376**	**826**	**54**	**—**	**(500)**	**48,346**
General Taxes and Other Assessments:							
Revenue Taxes	**51,321**	**2,793**	**2**	**—**	**—**	**—**	**54,116**
Other	**27,743**	**1,978**	**115**	**104**	**22**	**—**	**29,962**
Total Operating Expenses	**$ 621,317**	**$ 695,905**	**$ 31,392**	**$ 957**	**$ 2,397**	**$ (17,103)**	**$ 1,334,865**
Operating Income (Loss)	**220,633**	**8,935**	**1,158**	**4,007**	**(2,397)**	**—**	**232,336**
Other Income (Expense)—Net	**1,725**	**14**	**(1)**	**—**	**1,311**	**(55)**	**2,994**
Interest Expense	**19,170**	**38**	**—**	**—**	**190**	**(55)**	**19,343**
Dividends on Washington Gas Preferred Stock	**660**	**—**	**—**	**—**	**—**	**—**	**660**
Income Tax Expense (Benefit)	**85,771**	**3,601**	**323**	**1,492**	**(477)**	**—**	**90,710**
Net Income (Loss) Applicable to Common Stock	**$ 116,757**	**$ 5,310**	**$ 834**	**$ 2,515**	**$ (799)**	**$ —**	**$ 124,617**
Total Assets	**$3,537,030**	**$ 374,084**	**$ 39,069**	**$ 145,629**	**$183,413**	**$ (214,213)**	**$ 4,065,012**
Capital Expenditures	**$ 94,907**	**$ 523**	**$ 14,300**	**$ 101**	**$ 1**	**$ —**	**$ 109,832**
Equity Method Investments	**$ —**	**$ —**	**$ —**	**$ —**	**$ 16,559**	**$ —**	**$ 16,559**
Six Months Ended March 31, 2011							
Operating Revenues [(a)]	$ 988,100	$ 827,087	$ 14,774	$ 643	$ —	$ (17,509)	$ 1,813,095
Operating Expenses:							
Cost of Energy-Related Sales	512,699	738,814	12,304	—	—	(17,509)	1,246,308
Operation	113,249	25,317	2,153	327	1,801	—	142,847
Maintenance	22,252	—	—	—	—	—	22,252
Depreciation and Amortization	44,834	325	132	—	—	—	45,291
General Taxes and Other Assessments:							
Revenue Taxes	60,260	2,493	—	—	—	—	62,753
Other	29,523	2,259	119	7	14	—	31,922
Total Operating Expenses	782,817	769,208	14,708	334	1,815	(17,509)	1,551,373
Operating Income (Loss)	205,283	57,879	66	309	(1,815)	—	261,722
Other Income—Net	261	23	9	—	(624)	(101)	(432)
Interest Expense	20,242	83	—	—	94	(101)	20,318
Dividends on Washington Gas Preferred Stock	660	—	—	—	—	—	660
Income Tax Expense (Benefit)	73,115	23,210	95	122	(890)	—	95,652
Net Income (Loss) Applicable to Common Stock	$ 111,527	$ 34,609	$ (20)	$ 187	$ (1,643)	$ —	$ 144,660
Total Assets at March 31, 2011	$3,508,410	$ 325,193	$ 18,193	$ 52,678	$ 65,098	(99,873)	$ 3,869,699
Capital Expenditures	$ 70,214	$ 4,759	$ 11	$ —	—	—	$ 74,984
Equity Method Investments	$ —	$ —	$ —	$ —	$ 6,452	—	$ 6,452

[(a)] *Operating revenues are reported gross of revenue taxes. Revenue taxes of both the regulated utility and the retail energy-marketing segments include gross receipt taxes. Revenue taxes of the regulated utility segment also include PSC fees, franchise fees and energy taxes. Operating revenue amounts in the "Eliminations" column represent total intersegment revenues associated with sales from the regulated utility segment to the retail energy-marketing segment.*

NOTE 12. RELATED PARTY TRANSACTIONS

WGL Holdings and its subsidiaries engage in transactions during the ordinary course of business. Inter-company transactions and balances have been eliminated from the consolidated financial statements of WGL Holdings, except as described below. Washington Gas provides accounting, treasury, legal and other administrative and general support to affiliates, and files consolidated tax returns that include affiliated taxable transactions. The actual costs of these services are billed to the appropriate affiliates, which approximates the market value of the service provided. To the extent such billings for these services are not yet paid, they are reflected in "Receivables from associated companies" on Washington Gas' balance sheets. Washington Gas assigns or allocates these costs directly to its affiliates and, therefore, does not recognize revenues or expenses associated with providing these services.

In connection with billing for unregulated third party marketers and with other miscellaneous billing processes, Washington Gas collects cash on behalf of affiliates and transfers the cash in a reasonable time period. Cash collected by Washington Gas on behalf of its affiliates but not yet transferred is recorded in "Payables to associated companies" on Washington Gas' balance sheets.

At March 31, 2012 and September 30, 2011, Washington Gas recorded receivables from associated companies of $3.8 million and $21.2 million, respectively. At March 31, 2012 and September 30, 2011, Washington Gas recorded payables to associated companies of $28.1 million and $11.8 million, respectively.

Washington Gas provides gas balancing services related to storage, injections, withdrawals and deliveries to all energy marketers participating in the sale of natural gas on an unregulated basis through the customer choice programs that operate in its service territory. These balancing services include the sale of natural gas supply commodities related to various peaking arrangements contractually supplied to Washington Gas and then partially allocated and assigned by Washington Gas to the energy marketers, including WGEServices. Washington Gas records revenues for these balancing services pursuant to tariffs approved by the appropriate regulatory bodies. In conjunction with such services and the related sales and purchases of natural gas, Washington Gas charged WGEServices $9.3 million and $8.4 million for the three months ended March 31, 2012 and 2011, respectively. In the six months ended March 31, 2012 and 2011, the charges were $15.8 million and $17.5 million, respectively. These related party amounts have been eliminated in the consolidated financial statements of WGL Holdings.

As a result of these balancing services, an imbalance is created for volumes of natural gas received by Washington Gas that are not equal to the volumes of natural gas delivered to customers of the energy marketers. WGEServices recognized a payable to Washington Gas in the amount of $0.5 million and a receivable from Washington Gas in the amount of $2.1 million at March 31, 2012 and September 30, 2011, respectively, related to an imbalance in gas volumes. Due to regulatory treatment, these receivables are not eliminated in the consolidated financial statements of WGL Holdings. Refer to Note 1— *Accounting Policies* for further discussion of these imbalance transactions.

On June 29, 2011, Washington Gas implemented a Purchase of Receivables (POR) program as approved by the PSC of MD, whereby it purchases receivables from participating energy marketers at approved discount rates. In addition, WGEServices participates in POR programs with certain Maryland and Pennsylvania utilities, whereby it sells its receivables to various utilities, including Washington Gas, at approved discount rates. The receivables purchased by Washington Gas are included in "Accounts receivable" in the accompanying balance sheet. Any activity between Washington Gas and WGEServices related to the POR program has been eliminated in the accompanying financial statements for WGL Holdings. During the three and six months ended March 31, 2012, Washington Gas purchased $44.8 million and $71.4 million of receivables from WGEServices, respectively. This program was not in effect during the three and six month periods ended March 31, 2011.

Effective October 1, 2011, WGL Holdings began charging to its subsidiaries guarantee fees in an amount equal to the daily guarantee exposure multiplied by a monthly weighted average interest rate. During the three and six months ended March 31, 2012, the total fees charged by WGL Holdings to its subsidiaries were $0.2 million and $0.3 million, respectively. The majority of these fees were charged to WGEServices. These fees have been eliminated in the accompanying consolidated financial statements of WGL Holdings. Refer to Note 13— *Commitments and Contingencies* for further discussion of our guarantees.

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Notes to Consolidated Financial Statements (Unaudited)

NOTE 13. COMMITMENTS AND CONTINGENCIES

RATES AND REGULATORY MATTERS

Washington Gas determines its request to modify existing rates based on the level of net investment in plant and equipment, operating expenses and the need to earn a just and reasonable return on invested capital. The following is an update of significant current regulatory matters in each of Washington Gas' jurisdictions. For a more detailed discussion of the matters below, refer to our combined Annual Report on Form 10-K for WGL Holdings and Washington Gas for the fiscal year ended September 30, 2011.

District of Columbia Jurisdiction

Investigation of Depreciation Practices. On September 9, 2011, the Public Service Commission of the District of Columbia (PSC of DC) docketed a proceeding to review the proper and adequate rates of depreciation of the several classes of Washington Gas' property. In accordance with the procedural schedule, interested parties' comments were filed by October 24, 2011. Washington Gas' reply comments were filed on November 14, 2011, wherein Washington Gas requested that the PSC of DC consider depreciation issues in the context of the newly-initiated rate case, referenced below. On April 26, 2012, the PSC of DC granted Washington Gas' request to consolidate its investigation of depreciation issues into its base rate proceeding and closed the proceeding.

District of Columbia Base Rate Case. On November 2, 2011, the PSC of DC docketed a proceeding to investigate the reasonableness of Washington Gas' base rates and charges and required Washington Gas to file a base rate case no later than 90 days from the date of the order. On February 29, 2012, Washington Gas filed a request with the PSC of DC for a $29.0 million annual increase in revenues. The $29.0 million revenue increase requested in this application included a proposed overall rate of return 8.91% and a return on common equity of 10.90%. Washington Gas is also proposing to expand the existing program to replace or encapsulate certain vintage mechanical couplings, which was previously approved by the PSC of DC, to include the accelerated replacement of pipe in its system that is nearing the end of its useful life. Washington Gas plans to invest approximately $119.0 million to replace aging distribution pipe in the District of Columbia over the next five years and included in this proposal, a request for approval of these expenditures over the next five years. Washington Gas has provided a proposed procedural schedule and requested that the PSC of DC establish a pre-hearing conference. On April 26, 2012, the PSC of DC adopted a procedural schedule and designated issues for the proceeding. Intervenor testimony is due on July 17, 2012, rebuttal testimony is due August 31, 2012, and evidentiary hearings are scheduled to occur in October 2012.

Maryland Jurisdiction

Order on and Reviews of Purchased Gas Charges. Each year, the Maryland Public Service Commission (PSC of MD) reviews the annual gas costs collected from customers in Maryland to determine if Washington Gas' purchased gas costs are reasonable.

On September 9, 2011, the PSC of MD issued an order approving purchased gas charges of Washington Gas for the twelve-month period ending August 2009, except for an undetermined amount related to excess gas deliveries by competitive service providers (CSP) which were cashed-out by Washington Gas. The PSC of MD found that the cash-out of excess deliveries was in violation of Washington Gas' tariff and that Washington Gas should not have cashed-out the excess deliveries by CSPs, but rather should have eliminated the imbalances through volumetric adjustments in the future and designated that the hearing examiner in a separate proceeding determine whether civil penalties should be levied against Washington Gas. In accordance with generally accepted accounting principles, Washington Gas recorded a $5.3 million estimated regulatory liability associated with this decision during the fourth quarter of fiscal year 2011. On October 11, 2011, Washington Gas filed an application for rehearing of the order with respect to the decision that a violation of the tariff occurred and that civil penalties might be levied. Washington Gas requested that the PSC of MD find that Washington Gas is authorized to cash-out CSP account imbalances under its tariff and therefore is not subject to civil penalties. On January 3, 2012, the PSC of MD issued an order denying Washington Gas' request for rehearing. Pending the ultimate decision of the PSC of MD, further action may be taken with respect to recovery from the CSPs.

Investigation of Asset Management and Gas Purchase Practices. In 2008, the Office of Staff Counsel of the PSC of MD submitted a petition to the PSC of MD to establish an investigation into Washington Gas' asset management program and cost recovery of its gas purchases.

In November 2009, the Chief Hearing Examiner of the PSC of MD issued a Proposed Order of Hearing Examiner (POHE), which approved Washington Gas' proposal for the sharing of margins from asset optimization between Washington Gas and customers and its current methodology for pricing storage injections.

Subsequently, both the MD Staff and the Office of People's Counsel (OPC) filed notices of appeal of the POHE followed by a memorandum on appeal in support of their positions. In January 2010, Washington Gas filed a reply memorandum in response to the Staff of the PSC of MD and the OPC's memoranda on appeal. A decision by the PSC of MD is pending.

Maryland Base Rate Case. On November 14, 2011, the PSC of MD issued an order authorizing: *(i)* an annual revenue increase of $8.4 million compared to Washington Gas' revised request of $27.8 million; *(ii)* a rate of return on common equity of 9.60% and an overall rate of return of 8.09%; and *(iii)* an end of test period equity ratio of 57.88%. The order also authorized Washington Gas to implement the initial 5-year phase of the accelerated pipe replacement plan, but denied the proposed cost recovery mechanism; and disallowed the amortization of costs to achieve under Washington Gas' Business Process Outsourcing (BPO) agreement.

On December 14, 2011, Washington Gas filed a petition for rehearing and clarification of the PSC of MD's November 14, 2011 order to *(i)* correct the methodology used to calculate the adjustment related to interest synchronization, which would increase the revenue requirement determined by the PSC of MD in its order by $0.7 million, *(ii)* correct the omission of an adjustment related to "Other Tax Adjustments," which would increase the revenue requirement by an additional $2.4 million, and *(iii)* reverse the decision to disallow $1.0 million of Washington Gas' test period costs to achieve Washington Gas' BPO agreement. Washington Gas also requested clarification related to implementation of the accelerated pipe replacement plan and what annual reporting requirements may apply.

On March 29, 2012, the PSC of MD issued an order in response to the petition for rehearing and clarification filed by Washington Gas. The PSC of MD *(i)* granted an additional revenue increase of $0.7 million related to interest synchronization, increasing the overall revenue increase granted to Washington Gas in the case to $9.1 million; *(ii)* denied Washington Gas' request for an adjustment related to other tax adjustments, which would have increased the revenue requirement by an additional $2.4 million; *(iii)* denied recovery of the costs to initiate the outsourcing agreement with Accenture LLC in 2007; and *(iv)* directed Washington Gas to provide written notice when it implements the accelerated pipeline replacement project and adopted the reporting structure suggested by a PSC of MD Staff (MD Staff) witness as guidance for reporting Washington Gas' progress. As a result of this order, Washington Gas recorded a $2.8 million charge to income tax expense to write-off a regulatory asset that had been established in 2010 for the change in the tax treatment of Medicare Part D, the amortization of which comprised the majority of the other tax adjustments that were disallowed by the Commission.

On April 30, 2012, Washington Gas filed a petition for rehearing with the PSC of MD which requested the Commission to reverse its decisions in the March 29, 2012 order denying Washington Gas' request for an adjustment related to other tax adjustments and the costs to initiate the outsourcing agreement with Accenture, LLC. Washington Gas also filed a petition for judicial review of the PSC of MD's March 29, 2012 order with the Circuit Court for Baltimore City to preserve its right to appeal in this case. Washington Gas has requested the Circuit Court to hold further proceedings on the appeal in abeyance pending the PSC of MD's action on the petition for rehearing.

Virginia Jurisdiction

Conservation and Ratemaking Efficiency Plan. On July 22, 2010, Washington Gas filed an amendment to the CARE Plan to include small commercial and industrial customers in Virginia. The application included a portfolio of conservation and energy efficiency programs, an associated cost recovery provision and a decoupling mechanism that will adjust weather normalized non-gas distribution revenues for the impact of conservation or energy efficiency efforts. On November 18, 2010, the State Corporation Commission of Virginia (SCC of VA) issued an order that denied Washington Gas' application. The SCC of VA found that Washington Gas' current tariff and its underlying class cost of service and revenue apportionment studies do not segregate small versus large customers and that only small customers qualify under the CARE law. The SCC of VA stated that Washington Gas could amend the underlying tariff and studies in connection with its required 2011 base rate case filing. Such a tariff amendment was proposed in the new base rate case filing made with the SCC of VA, which is pending a commission decision.

Virginia Base Rate Case. On January 31, 2011, Washington Gas filed a request with the SCC of VA for a $29.6 million annual increase in revenues. The filing was made pursuant to the settlement agreement reached by the parties and approved by the SCC of VA in Washington Gas' last base rate case, which resulted in a Performance-Based Rate (PBR) plan. On May 12, 2011, Washington Gas revised its requested revenue increase from $29.6 million to $28.5 million as a result of new proposed depreciation rates. Interim rates went into effect on October 1, 2011 with the requested increase subject to refund pending a final commission decision.

On November 30, 2011, Washington Gas filed a stipulation to reflect settlement terms to which Washington Gas, the Staff, and other stipulating parties to the settlement agreed. The Apartment and Office Building Association (AOBA) did not support this stipulation. In the stipulation, the settling parties agreed to a $20.0 million rate increase, a 9.75% return on equity, an 8.261% overall rate of return, and a provision for sharing margins from asset optimization activities between Washington Gas and customers which includes a $3.2 million annual guarantee. Evidentiary hearings were held on December 5 and 6, 2011. Post-hearing briefs were filed on January 26, 2012. On March 15, 2012, the Senior Hearing Examiner issued a report of findings and recommended that the SCC of

VA adopt the stipulation. On April 5, 2012, Washington Gas, the Staff of the SCC of VA, the Office of the Attorney General and Fairfax County all filed comments in support of the recommended decision of the Hearing Examiner while the AOBA filed comments in opposition. On April 18, 2012, Washington Gas filed a petition for leave to file reply and reply to AOBA's comments on the Hearing Examiner's report. A commission decision is pending.

Affiliate Transactions. On June 16, 2011, Washington Gas submitted an application to the SCC of VA requesting approval of three affiliate transactions with CEV: *(i)* the transfer to CEV of the remainder of the term of two agreements for natural gas storage service at the Washington Storage Service (WSS) and Eminence Storage Service (ESS) storage fields; *(ii)* the sale to CEV of any storage gas balances associated with the WSS and ESS agreements; and *(iii)* the assignment to CEV of Washington Gas' rights to buy base gas in the WSS storage field. Washington Gas proposed to make these affiliate transactions by September 30, 2011, coincident with the expiration of its PBR plan approved by the SCC of VA in a separate proceeding. On September 14, 2011, the SCC of VA issued an order denying Washington Gas' application to transfer Washington Gas' contracts for certain storage capacity resources to its affiliate, CEV. On October 4, 2011, Washington Gas filed a petition for reconsideration on this proceeding. On October 5, 2011, the SCC of VA granted Washington Gas' request that the matter be reconsidered, but has not made a final ruling on Washington Gas' petition for reconsideration. On December 6, 2011, the Staff of the SCC of VA (VA Staff) submitted a supplement to action brief seeking to provide evidence to the commission that ratepayers have been funding the WSS and ESS assets during the PBR period based on the netting of costs associated with those assets when calculating net revenues. Washington Gas submitted comments rejecting the Staff's position and showing that the ratepayers had not funded these assets. These comments were appended to the VA Staff's brief on December 9, 2011. A commission decision is pending.

NON UTILITY OPERATIONS

Construction Project Financing

To fund certain of its construction projects, Washington Gas enters into financing arrangements with third party lenders. As part of these financing arrangements, Washington Gas' customers agree to make principal and interest payments over a period of time, typically beginning after the projects are completed. Washington Gas assigns these customer payment streams to the lender. As the lender funds the construction project, Washington Gas establishes a receivable representing its customers' obligations to remit principal and interest and a long-term payable to the lender. When these projects are formally "accepted" by the customer as completed, Washington Gas transfers the ownership of the receivable to the lender and removes both the receivable and the long-term financing from its financial statements. As of March 31, 2012 and September 30, 2011, work on these construction projects that was not completed or accepted by customers was valued at $2.8 million and $4.2 million, respectively, which are recorded on the balance sheet as a receivable in "Deferred Charges and Other Assets—Other" with the corresponding long-term obligation to the lender in "Long-term debt." At any time before these contracts are accepted by the customer, should there be a contract default, such as, among other things, a delay in completing the project, the lender may call on Washington Gas to fund the unpaid principal in exchange for which Washington Gas would receive the right to the stream of payments from the customer. Construction projects are financed primarily for government agencies, which Washington Gas considers to have minimal credit risk. Based on this assessment and previous collection experience, Washington Gas did not record a corresponding reserve for bad debts related to these receivables at March 31, 2012 and September 30, 2011.

Financial Guarantees

WGL Holdings guaranteed payments primarily for certain purchases of natural gas and electricity on behalf of WGEServices and for certain purchase commitments of CEV. At March 31, 2012, these guarantees totaled $532.5 million and $122.6 million for WGEServices and CEV, respectively. The amount of such guarantees is periodically adjusted to reflect changes in the level of financial exposure related to these purchase commitments. We also receive financial guarantees or other collateral from counterparties when required by our credit policy. WGL Holdings also issued guarantees totaling $3.0 million at March 31, 2012 on behalf of certain of our non-utility subsidiaries associated with their banking transactions. Of the total guarantees of $658.1 million, $4.8 million expired on April 30, 2012, and $22.2 million is due to expire on October 31, 2012. The remaining guarantees do not have specific maturity dates. For all of its financial guarantees, WGL Holdings may cancel any or all future obligations imposed by the guarantees upon written notice to the counterparty, but WGL Holdings would continue to be responsible for the obligations created under the guarantees prior to the effective date of the cancellation.

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NOTE 14. PENSION AND OTHER POST-RETIREMENT BENEFIT PLANS

The following tables show the components of net periodic benefit costs (income) recognized in our financial statements during the three and six months ended March 31, 2012 and 2011:

Components of Net Periodic Benefit Costs (Income)

	Three Months Ended March 31,			
	2012		2011	
(In millions)	**Pension Benefits**	**Health and Life Benefits**	Pension Benefits	Health and Life Benefits
Components of net periodic benefit costs (income)				
Service cost	**$ 3.2**	**$ 2.0**	$ 3.0	$ 1.8
Interest cost	**10.1**	**6.3**	10.3	6.3
Expected return on plan assets	**(10.9)**	**(4.7)**	(11.1)	(4.6)
Amortization of prior service cost	**0.3**	**(1.0)**	0.3	(1.0)
Amortization of actuarial loss	**4.0**	**3.3**	3.7	2.8
Amortization of transition obligation	**—**	**0.3**	—	0.3
Net periodic benefit cost	**6.7**	**6.2**	6.2	5.6
Amount allocated to construction projects	**(0.7)**	**(0.9)**	(0.8)	(0.9)
Amount deferred as regulatory asset (liability) — net	**(1.9)**	**0.3**	(1.8)	0.5
Amount charged to expense	**$ 4.1**	**$ 5.6**	$ 3.6	$ 5.2

Components of Net Periodic Benefit Costs (Income)

	Six Months Ended March 31,			
	2012		2011	
(In millions)	**Pension Benefits**	**Health and Life Benefits**	Pension Benefits	Health and Life Benefits
Components of net periodic benefit costs (income)				
Service cost	**$ 6.4**	**$ 4.0**	$ 6.0	$ 3.6
Interest cost	**20.2**	**12.6**	20.6	12.6
Expected return on plan assets	**(21.8)**	**(9.4)**	(22.2)	(9.2)
Amortization of prior service cost	**0.6**	**(2.0)**	0.6	(2.0)
Amortization of actuarial loss	**8.0**	**6.6**	7.4	5.6
Amortization of transition obligation	**—**	**0.6**	—	0.6
Net periodic benefit cost	**13.4**	**12.4**	12.4	11.2
Amount allocated to construction projects	**(1.5)**	**(1.9)**	(1.6)	(1.7)
Amount deferred as regulatory asset (liability) — net	**(3.7)**	**0.8**	(3.6)	1.0
Amount charged to expense	**$ 8.2**	**$ 11.3**	$ 7.2	$ 10.5

Amounts included in the line item “Amount deferred as regulatory asset/liability-net,” as shown in the table above, represent the difference between the cost of the applicable Pension Benefits or the Health and Life Benefits and the amount that Washington Gas is permitted to recover in rates that it charges to customers in the District of Columbia.

During fiscal year 2012, Washington Gas expects to make contributions totaling $24.2 million to its qualified pension plan.

NOTE 15. SUBSEQUENT EVENTS

Credit Facilities

On April 3, 2012, WGL Holdings and Washington Gas each entered into separate revolving credit agreements to replace the existing revolving credit agreements which were due to expire in August 2012. The credit facility for WGL Holdings permits it to borrow up to $450 million, and further permits, with the banks’ approval, additional borrowings of $100 million for a maximum potential total of $550 million. The credit facility for Washington Gas permits it to borrow up to $350 million, and further permits, with the banks’ approval, additional borrowings of $100 million for a maximum potential total of $450 million. The interest rate on loans made under the credit facilities will be a fluctuating rate per annum that will be set using certain parameters at the time each loan is made. These credit agreements provide for a term of five years and expire on April 3, 2017. The credit agreements each have two one-year extension options.

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Springfield Operations Center

On April 30, 2012, Washington Gas completed the relocation of its employees from its existing facility to the new operations facility. Washington Gas plans to sell the existing facility, which had a carrying value of $30.1 million at April 30, 2012.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

This Management's Discussion analyzes the financial condition, results of operations and cash flows of WGL Holdings, Inc. (WGL Holdings) and its subsidiaries. Except where the content clearly indicates otherwise, "WGL Holdings," "we," "us" or "our" refers to the holding company or the consolidated entity of WGL Holdings and all of its subsidiaries.

Management's Discussion is divided into the following two major sections:

— ***WGL Holdings*** —This section describes the financial condition and results of operations of WGL Holdings and its subsidiaries on a consolidated basis. It includes discussions of our regulated operations, including Washington Gas and Hampshire Gas Company (Hampshire), and our non-utility operations.

— ***Washington Gas Light Company (Washington Gas)*** —This section describes the financial condition and results of operations of Washington Gas, a wholly owned subsidiary of WGL Holdings, which comprises the majority of the regulated utility segment.

Both sections of Management's Discussion—WGL Holdings and Washington Gas—are designed to provide an understanding of our operations and financial performance and should be read in conjunction with the respective company's financial statements and the combined Notes to Consolidated Financial Statements in this quarterly report as well as our combined Annual Report on Form 10-K for WGL Holdings and Washington Gas for the fiscal year ended September 30, 2011 (2011 Annual Report).

Unless otherwise noted, earnings per share amounts are presented on a diluted basis, and are based on weighted average common and common equivalent shares outstanding. Our operations are seasonal and, accordingly, our operating results for the interim periods presented are not indicative of the results to be expected for the full fiscal year.

EXECUTIVE OVERVIEW

Introduction

WGL Holdings, through its wholly owned subsidiaries, sells and delivers natural gas and provides a variety of energy-related products and services to customers primarily in the District of Columbia and the surrounding metropolitan areas in Maryland, Virginia, as well as in Pennsylvania and Delaware.

In the first quarter of 2012, we made certain changes to our operating segment reporting to reflect the recent growth of our non-utility business activities and the impact of those activities on our financial performance. Commercial solar projects, energy efficiency projects and combined heat and power projects, which we own and manage directly, including activities of Washington Gas Energy Systems, Inc. (WGESystems) are reported within a newly-defined operating segment entitled commercial energy systems. We also established wholesale energy solutions as a new segment that contains the activities of Capitol Energy Ventures Corp. (CEV), our non-utility asset optimization business, which we began in fiscal year 2010. Prior period operating segment information has been recast to conform to current quarter presentation.

These changes improve visibility into our operations and better align our reporting with current management accountability. Our four segments are described below.

Regulated Utility. With approximately 87% of our consolidated total assets, the regulated utility segment consists of Washington Gas and Hampshire. Washington Gas delivers natural gas to retail customers in accordance with tariffs approved by the regulatory commissions that have jurisdiction over Washington Gas' rates. Washington Gas also sells natural gas to customers who have not elected to purchase natural gas from unregulated third party marketers.

The rates charged to utility customers are designed to recover Washington Gas' operating expenses and natural gas commodity costs and to provide a return on its investment in the net assets used in its firm gas sales and delivery service. Washington Gas recovers the cost of the natural gas purchased to serve firm customers through the gas cost recovery mechanisms as approved in jurisdictional tariffs. Any difference between the firm customer gas costs incurred and the gas costs recovered from those firm customers is deferred on the balance sheet as an amount to be collected from or refunded to customers in future periods. Therefore, increases or decreases in the cost of gas associated with sales made to firm customers have no direct effect on Washington Gas' net revenues and net income.

Washington Gas' asset optimization program utilizes Washington Gas' storage and transportation capacity resources when those assets are not fully utilized to physically serve utility customers. The objective of this program is to derive a profit to be shared with its utility customers (refer to the section entitled "Market Risk" for further discussion of our asset optimization program) by entering into commodity-related physical and financial contracts with third parties. Unless otherwise noted, therm deliveries shown related to Washington Gas or the regulated utility segment do not include therm deliveries related to our asset optimization program.

Hampshire, a wholly owned subsidiary of WGL Holdings, is regulated by the FERC. Hampshire operates and owns full and partial interests in underground natural gas storage facilities including pipeline delivery facilities located in and around Hampshire County, West Virginia. Washington Gas purchases all of the storage services of Hampshire and includes the cost of these services in the bills sent to its customers. Hampshire operates under a "pass-through" cost of service-based tariff approved by the FERC, and adjusts its billing rates to Washington Gas on a periodic basis to account for changes in its investment in utility plant and associated expenses.

Retail Energy-Marketing. The retail energy-marketing segment consists of the operations of Washington Gas Energy Services, Inc. (WGEServices), a wholly owned subsidiary of Washington Gas Resources, which is a wholly owned subsidiary of WGL Holdings. WGEServices competes with regulated utilities and other unregulated third party marketers to sell natural gas and/or electricity directly to residential, commercial and industrial customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. WGEServices contracts for its supply needs and buys and resells natural gas and electricity with the objective of earning a profit through competitively priced contracts with end-users. These commodities are delivered to retail customers through the distribution systems owned by regulated utilities such as Washington Gas or other unaffiliated natural gas or electric utilities.

Commercial Energy Systems. The commercial energy systems segment consists of commercial solar projects, energy efficiency projects and combined heat and power projects, which we own and manage directly, including activities of WGESystems, a wholly owned subsidiary of Washington Gas Resources. WGESystems focuses on upgrading the mechanical, electrical, water and energy-related systems of large government and commercial facilities by implementing both traditional as well as alternative energy technologies, primarily in the District of Columbia, Maryland and Virginia. WGESystems is also increasing its investments in commercial solar, energy efficiency, and combined heat and power projects, which we own and manage directly. This expansion includes the ownership and management of its renewable energy producing assets. These investments are part of our long-term commitment to providing clean and efficient energy solutions to our customers and communities in select markets across the United States.

Wholesale Energy Solutions. The wholesale energy solutions segment, which consists of the operations of CEV, engages in acquiring, managing and optimizing natural gas storage and transportation assets. CEV enters into both physical and financial transactions in a manner intended to utilize the most effective energy risk management products available to mitigate risks while maximizing potential profits from the optimization of these assets under its management.

Other Activities. Activities and transactions that are not significant enough on a stand-alone basis to warrant treatment as an operating segment, and that do not fit into one of our other operating segments, are aggregated as "Other activities" and included as part of non-utility operations as presented below in the operating segment financial information. These activities include the operations of WGSW, Inc. (WGSW), a wholly owned subsidiary of Washington Gas Resources, which is a holding company formed to invest in alternative energy power generating facilities. Administrative costs associated with WGL Holdings and Washington Gas Resources are also included in "Other activities."

PRIMARY FACTORS AFFECTING WGL HOLDINGS AND WASHINGTON GAS

The principal business, economic and other factors that affect our operations and/or financial performance include:

- weather conditions and weather patterns;
- regulatory environment, regulatory decisions and changes in legislation;
- availability of natural gas supply and pipeline transportation and storage capacity;
- diversity of natural gas supply;
- volatility of natural gas and electricity prices;
- non-weather related changes in natural gas consumption patterns;
- maintaining the safety and reliability of the natural gas distribution system;
- competitive environment;
- environmental matters;
- industry consolidation;
- economic conditions and interest rates;
- inflation/deflation;
- use of business process outsourcing;
- labor contracts, including labor and benefit costs; and
- changes in accounting principles.

For further discussion of the factors listed above, refer to Management's Discussion within the 2011 Annual Report. Also, refer to the section entitled *"Safe Harbor for Forward-Looking Statements"* included in this quarterly report for a listing of forward-looking statements related to factors affecting WGL Holdings and Washington Gas.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements and related disclosures in compliance with GAAP requires the selection and the application of appropriate technical accounting guidance to the relevant facts and circumstances of our operations, as well as our use of estimates to compile the consolidated financial statements. The application of these accounting policies involves judgment regarding estimates and projected outcomes of future events, including the likelihood of success of particular regulatory initiatives, the likelihood of realizing estimates for legal and environmental contingencies and the probability of recovering costs and investments in both the regulated utility and non-utility business segments.

We have identified the following critical accounting policies that require our judgment and estimation, where the resulting estimates may have a material effect on the consolidated financial statements:

- accounting for unbilled revenue;
- accounting for regulatory operations — regulatory assets and liabilities;
- accounting for income taxes;
- accounting for contingencies;
- accounting for derivative instruments;
- accounting for pension and other post-retirement benefit plans and
- accounting for stock based compensation.

For a description of these critical accounting policies, refer to Management's Discussion within the 2011 Annual Report. There were no new critical accounting policies or changes to our critical accounting policies during the six month period ended March 31, 2012.

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WGL HOLDINGS, INC.

RESULTS OF OPERATIONS — Three Months Ended March 31, 2012 vs. March 31, 2011

We analyze the operating results using utility net revenues for the regulated utility segment and gross margins for the retail energy-marketing segment. Both utility net revenues and gross margins are calculated as revenues less the associated cost of energy and applicable revenue taxes. We believe utility net revenues is a better measure to analyze profitability than gross operating revenues for our regulated utility segment because the cost of the natural gas commodity and revenue taxes are generally included in the rates that Washington Gas charges to customers as reflected in operating revenues. Accordingly, changes in the cost of gas and revenue taxes associated with sales made to customers generally have no direct effect on utility net revenues, operating income or net income. We consider gross margins to be a better reflection of profitability than gross revenues or gross energy costs for our retail energy-marketing segment because gross margins are a direct measure of the success of our core strategy for the sale of natural gas and electricity.

Neither utility net revenues nor gross margins should be considered as an alternative to, or a more meaningful indicator of our operating performance, than net income. Our measures of utility net revenues and retail energy-marketing gross margins may not be comparable to similarly titled measures of other companies. Refer to the sections entitled *"Results of Operations—Regulated Utility Operating Results"* and *"Results of Operations—Retail Energy-Marketing"* for the calculation of utility net revenues and gross margins, respectively, as well as a reconciliation to operating income and net income for both segments.

Summary Results

WGL Holdings reported net income of $74.2 million and $79.4 million for the three months ended March 31, 2012 and 2011, respectively. For the twelve month periods ended March 31, 2012 and 2011, we earned a return on average common equity of 7.6% and 10.4%, respectively.

The following table summarizes our net income (loss) by operating segment for the three months ended March 31, 2012 and 2011.

Net Income (Loss) by Operating Segment

(In millions)	Three Months Ended March 31, **2012**	2011	Increase/ (Decrease)
Regulated Utility	**$ 72.4**	$ 70.8	$ 1.6
Non-utility operations:			
Retail Energy-Marketing	**4.5**	9.7	(5.2)
Commercial Energy Systems	**0.5**	—	0.5
Wholesale Energy Solutions	**(2.7)**	0.1	(2.8)
Other Activities	**(0.5)**	(1.2)	0.7
Total non-utility	1.8	8.6	(6.8)
Net income applicable to common stock	**$ 74.2**	$ 79.4	$ (5.2)
EARNINGS PER AVERAGE COMMON SHARE			
Basic	**$ 1.44**	$ 1.55	$ (0.11)
Diluted	**$ 1.44**	$ 1.55	$ (0.11)

Regulated Utility Operating Results

The following table summarizes the regulated utility segment's operating results for the three months ended March 31, 2012 and 2011.

Regulated Utility Operating Results

(In millions)	Three Months Ended March 31, **2012**	Three Months Ended March 31, 2011	Increase/ Decrease
Utility net revenues:			
Operating revenues	**$ 471.1**	$ 569.7	$ (98.6)
Less: Cost of gas	**197.7**	295.0	(97.3)
Revenue taxes	**28.7**	34.3	(5.6)
Total utility net revenues	**244.7**	240.4	4.3
Operation and maintenance	**68.7**	72.3	(3.6)
Depreciation and amortization	**23.8**	22.4	1.4
General taxes and other assessments	**16.0**	17.0	(1.0)
Operating income	**136.2**	128.7	7.5
Other income (expense)-net, including preferred stock dividends	**0.6**	(1.0)	1.6
Interest expense	**9.4**	10.3	(0.9)
Income tax expense	**55.0**	46.6	8.4
Net income applicable to common stock	**$ 72.4**	$ 70.8	$ 1.6

The regulated utility segment's net income applicable to common stock was $72.4 million for the three months ended March 31, 2012, compared to net income of $70.8 million for the same three month period in 2011, primarily due to: *(i)* $9.8 million in higher revenues due to the implementation of new rates in Maryland and Virginia; *(ii)* a $5.9 million increase in unrealized margins associated with our asset optimization program; *(iii)* $3.6 million in lower operation and maintenance expenses, including a $5.3 million benefit from our weather protection and *(iv)* a $2.2 million increase in revenues related to growth of more than 7,900 average active customer meters. Partially offsetting these increases were: *(i)* a $8.4 million reduction in revenue attributed to warmer weather, excluding the benefit of our weather protection; *(ii)* $4.5 million in higher income taxes due to an increase in the effective tax rate including a $2.8 million write off of a regulatory asset originally recognized in 2010 related to the tax effect of Medicare Part D (Med D); *(iii)* $2.6 million in lower realized margins, net of margin sharing, associated with our asset optimization program and *(iv)* an increase of $1.4 million in depreciation expense due to the growth in, and changes in the asset mix of, our investment in utility plant.

Utility Net Revenues . The following table provides the key factors contributing to the changes in the utility net revenues of the regulated utility segment between the three months ended March 31, 2012 and 2011.

Composition of Changes in Utility Net Revenues

(In millions)	Increase/ (Decrease)
Customer growth	$ 2.2
Impact of approved rates in MD and VA	9.8
Asset optimization:	
Realized margins	(2.6)
Unrealized mark-to-market valuations	5.9
Lower-of-cost or market adjustment	(1.2)
Estimated weather effects	(8.4)
Other	(1.4)
Total	$ 4.3

Customer growth — Average active customer meters increased by more than 7,900 for the three months ended March 31, 2012 compared to the same quarter of the prior fiscal year.

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Impact of approved rates in MD and VA — New base rates were approved in Maryland and Virginia effective November 14, 2011 and October 1, 2011, respectively.

Asset optimization — We recorded net unrealized gains associated with our energy-related derivatives of $1.2 million and unrealized losses of $4.7 million for the three months ended March 31, 2012 and 2011, respectively. When these derivatives settle, any unrealized amounts will ultimately be reversed, and Washington Gas will realize margins when combined with the related transactions these derivatives economically hedge. Unfavorably affecting asset optimization results were $2.6 million of lower realized margins due to a change in Virginia margin sharing and $1.2 million of lower-of-cost or market adjustments associated with storage capacity assets utilized for asset optimization during the three months ended March 31, 2012. There were no lower-of-cost or market adjustments during the three months ended March 31, 2011. Refer to the section entitled *"Market Risk—Price Risk Related to the Regulated Utility Segment"* for a further discussion of our asset optimization program.

Estimated weather effects — Weather, when measured by HDDs, was 23.6% warmer and 4.6% colder than normal for the three months ended March 31, 2012 and 2011, respectively. Washington Gas has a weather protection strategy that is designed to neutralize the estimated financial effects of variations from normal weather on net income (refer to the section entitled *"Weather Risk"* for further discussion of our weather protection strategy). Washington Gas executed heating degree day derivative contracts to manage its exposure to variations from normal weather in the District of Columbia. Changes in the fair value of these derivatives are reflected in operation and maintenance expenses and offset the weather effects reflected above. Due to the extremely warm weather, our weather protection instruments were not sufficient to offset approximately $3.1 million of the reduction in revenue for the three months ended March 31, 2012. There were no material effects on net income attributed to colder or warmer weather for the three months ended March 31, 2011.

Operation and Maintenance Expenses . The following table provides the key factors contributing to the changes in operation and maintenance expenses of the regulated utility for the three months ended March 31, 2012 compared to the same period in 2011.

Composition of Changes in Operation and Maintenance Expenses

(In millions)	Increase/ (Decrease)
Operations, engineering, construction and safety	$ 1.7
Employee benefits	1.2
Hexane costs	1.0
Weather derivative benefits:	
Benefit	(5.3)
Premium costs and fair value effects	(0.7)
Other operating expenses	(1.5)
Total	$ (3.6)

Operation, engineering, compliance and safety — The increase in operation, engineering, construction and safety costs during the quarter ended March 31, 2012 compared to the same quarter of the prior year is primarily due to higher costs due to an increase in the volume of projects.

Employee benefits — The increase in employee benefits expense reflects higher pension and other post-retirement benefits due to changes in discount rate and other plan assumptions used to measure the benefit obligation.

Hexane costs — The increase in expense during the quarter ended March 31, 2012 compared to the same quarter of the prior year reflects the deferral of costs in 2011 to a regulatory asset under the regulatory mechanism that was in existence at the time.

Weather derivative benefits — The effects of hedging variations from normal weather in the District of Columbia for the three months ended March 31, 2012 and 2011 are recorded to operation and maintenance expense. Washington Gas recorded a gain of $4.2 million as a direct result of warmer than normal weather in the quarter ended March 31, 2012 and a loss of $1.1 million during the quarter ended March 31, 2011 due to colder than normal weather during that period. The benefits or losses of the weather-related instruments are generally offset by the effect of weather on utility net revenues; however, during the quarter ended March 31, 2012, the warmer than normal weather exceeded the level of our hedging protection. In addition, net premiums received related to the weather derivatives were higher due to market expectations of weather.

Depreciation and Amortization. The increase of $1.4 million in depreciation and amortization is primarily attributed to growth in, and changes in the asset mix of, our investment in utility plant partially offset by a reduction in Virginia depreciation rates.

Retail Energy-Marketing Financial and Statistical Data

	Three Months Ended March 31,		Increase /
	2012	2011	(Decrease)
Operating Results *(In millions)*			
Gross margins:			
Operating revenues	**$ 368.4**	$ 447.7	$ (79.3)
Less: Cost of energy	**343.9**	415.7	(71.8)
Revenue taxes	**1.5**	1.6	(0.1)
Total gross margins	**23.0**	30.4	(7.4)
Operation expenses	**14.2**	13.0	1.2
Depreciation and amortization	**0.2**	0.2	—
General taxes and other assessments	**0.9**	1.1	(0.2)
Operating income	**7.7**	16.1	(8.4)
Income tax expense	**3.2**	6.4	(3.2)
Net income	**$ 4.5**	$ 9.7	$ (5.2)
Realized margins	**$ 5.0**	$ 12.1	$ (7.1)
Unrealized mark-to-market gains	**2.4**	2.8	(0.4)
Total gross margins — natural gas	**7.4**	14.9	(7.5)
Realized margins	**19.5**	15.5	4.0
Unrealized mark-to-market losses	**(3.9)**	—	(3.9)
Total gross margins — electricity	**15.6**	15.5	0.1
Total gross margins	**$ 23.0**	$ 30.4	$ (7.4)
Other Retail-Energy Marketing Statistics			
Natural gas			
Therm sales *(millions of therms)*	**249.6**	302.4	(52.8)
Number of customers *(end of period)*	**179,000**	173,400	5,600
Electricity			
Electricity sales *(millions of kWhs)*	**2,896.4**	2,611.0	285.4
Number of accounts *(end of period)*	**197,000**	183,700	13,300

The retail energy-marketing segment reported net income of $4.5 million for the three months ended March 31, 2012, compared to net income of $9.7 million reported for the same three-month period of the prior fiscal year.

The decrease in net income primarily reflects lower gross margins from natural gas sales. Period-to-period comparisons of quarterly gross margins for this segment can vary significantly and are not necessarily representative of expected annualized results.

Gross margins from natural gas sales decreased $7.5 million in the current quarter of fiscal year 2012 when compared to the same quarter in the prior fiscal year. This decrease is primarily due to the unfavorable change in unrealized mark-to-market margins on energy-related derivatives of $0.4 million resulting from fluctuating market prices and lower realized margins of $7.1 million due to lower retail sales volumes resulting from warmer weather and a less favorable pattern of margin recognition in the current quarter versus the same quarter of the prior year.

Gross margins from electric sales in the current quarter increased $0.1 million from the same quarter of the prior period. This increase reflects higher realized electric retail margins of $4.0 million due to favorable price conditions, higher sales volumes due to customer growth, and a more favorable pattern of margin recognition in the current quarter versus the same quarter of the prior year, partially offset by $3.9 million in unrealized margins due to fluctuating market prices.

The retail energy-marketing segment's increase in new electricity customer accounts compared to the prior year is primarily due to WGEServices being able to offer customers lower prices than utility standard offer service rates and the addition of new government and commercial accounts.

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Commercial Energy Systems

The commercial energy systems segment reported net income of $0.5 million for the second quarter of fiscal year 2012, compared to a net loss of $18,000 reported for the same period of fiscal year 2011. This increase is due to higher revenue from commercial solar projects and the commencement of project work for government agency customers that was delayed in the prior year.

Wholesale Energy Solutions

The wholesale energy solutions segment reported a net loss of $2.7 million for the three months ended March 31, 2012, compared to net income of $0.1 million reported for the same period of the prior fiscal year. This decrease is primarily due to lower storage and transportation spreads due to one of the warmest winters on record across the country, which affected optimization opportunities as well as higher operation and maintenance expense associated with new storage and optimization arrangements.

Other Non-Utility

Transactions that are not significant enough on a stand-alone basis to warrant treatment as an operating segment, and that do not fit into one of our four operating segments, are aggregated as "Other Activities" and included as part of non-utility operations. Results from our other non-utility activities reflect net losses of $0.5 million and $1.2 million for the three months ended March 31, 2012 and 2011, respectively.

RESULTS OF OPERATIONS — Six Months Ended March 31, 2012 vs. March 31, 2011

Summary Results

WGL Holdings reported net income applicable to common stock of $124.6 million, or $2.42 per share, for the six months ended March 31, 2012 compared to $144.7 million, or $2.83 per share, reported for the six months ended March 31, 2011.

The following table summarizes our net income (loss) applicable to common stock by operating segment for the six months ended March 31, 2012 and 2011.

Net Income (Loss) by Operating Segment

(In millions)	Six Months Ended March 31, **2012**	2011	Increase/ (Decrease)
Regulated Utility	**$ 116.8**	$ 111.5	$ 5.3
Non-utility operations:			
Retail Energy-Marketing	**5.3**	34.6	(29.3)
Commercial Energy Systems	**0.8**	—	0.8
Wholesale Energy Solutions	**2.5**	0.2	2.3
Other Activities	**(0.8)**	(1.6)	0.8
Total non-utility	7.8	33.2	(25.4)
Net income applicable to common stock	**$ 124.6**	$ 144.7	$ (20.1)
EARNINGS PER AVERAGE COMMON SHARE			
Basic	**$ 2.42**	$ 2.83	$ (0.41)
Diluted	**$ 2.42**	$ 2.83	$ (0.41)

Regulated Utility Operating Results

The following table summarizes the regulated utility segment's operating results for the six months ended March 31, 2012 and 2011.

Regulated Utility Operating Results

(In millions)	Six Months Ended March 31, **2012**	2011	Increase/ (Decrease)
Utility net revenues:			
Operating revenues	**$ 842.0**	$ 988.1	$ (146.1)
Less: Cost of gas	**359.6**	512.7	(153.1)
Revenue taxes	**51.3**	60.3	(9.0)
Total utility net revenues	**431.1**	415.1	16.0
Operation and maintenance	**135.1**	135.5	(0.4)
Depreciation and amortization	**47.5**	44.8	2.7
General taxes and other assessments	**27.7**	29.5	(1.8)
Operating income	**220.8**	205.3	15.5
Other income (expenses)-net, including preferred stock dividends	**1.0**	(0.5)	1.5
Interest expense	**19.2**	20.2	(1.0)
Income tax expense	**85.8**	73.1	12.7
Net income	**$ 116.8**	$ 111.5	$ 5.3

The regulated utility segment’s net income applicable to common stock was $116.8 million for the six months ended March 31, 2012 compared to $111.5 million for the same six month period of the prior fiscal year. The increase in net income primarily reflects: *(i)* $16.1 million in higher revenues due to the implementation of new rates in Maryland and Virginia; *(ii)* a $16.0 million increase in unrealized margins associated with our asset optimization program and *(iii)* a $3.3 million increase in revenues related to growth of more than 8,700 average customer meters. Partially offsetting these favorable variances were: *(i)* a $5.6 million decrease in realized margins, net of margin sharing, associated with our asset optimization program; *(ii)* $5.6 million in higher income taxes due to an increase in the effective tax rate including a $2.8 million write off of a regulatory asset originally recognized in 2010 related to the tax effect of Med D and *(iii)* a $2.7 million increase in depreciation expense due to the growth in, and changes in the asset mix of, our investment in utility plant.

Utility Net Revenues . The following table provides the key factors contributing to the changes in the utility net revenues of the regulated utility segment between the six months ended March 31, 2012 and 2011.

Composition of Changes in Utility Net Revenues

(In millions)	Increase / (Decrease)
Customer growth	$ 3.3
Impact of approved rates in MD and VA	16.1
Asset optimization:	
Realized margins	(5.6)
Unrealized mark-to-market valuations	16.0
Lower-of-cost or market adjustment	(1.6)
Estimated weather effects	(12.5)
Other	0.3
Total	$ 16.0

Customer growth — Average active customer meters increased by more than 8,700 for the six months ended March 31, 2012 compared to the same period of the prior fiscal year.

Impact of approved rates in MD and VA — New base rates were approved in Maryland and Virginia effective November 14, 2011 and October 1, 2011, respectively.

Asset optimization — We recorded unrealized gains associated with our energy-related derivatives of $1.4 million for the six months ended March 31, 2012 compared to unrealized losses of $14.6 million for the same period of 2011. When these derivatives settle, any unrealized amounts will ultimately be reversed, and Washington Gas will realize margins in combination with the related transactions that these derivatives economically hedge. Unfavorably affecting asset optimization results were $5.6 million of lower realized margins due to a change in Virginia margin sharing and $1.6 million of lower-of-cost or market adjustments associated with market adjustments during the six months ended March 31, 2012. There were no lower-of-cost or market adjustments during the six months ended March 31, 2011. (Refer to the section entitled *“Market Risk—Price Risk Related to the Regulated Utility Segment”* for a further discussion of our asset optimization program).

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Estimated weather effects — Weather, when measured by HDDs, was 18.9% warmer and 7.4% colder than normal for the six months ended March 31, 2012 and 2011, respectively. Washington Gas has a weather protection strategy that is designed to neutralize the estimated financial effects of variations from normal weather on net income (refer to the section entitled *"Weather Risk"* for further discussion of our weather protection strategy). Washington Gas executed heating degree day derivative contracts to manage its exposure to variations from normal weather in the District of Columbia. Changes in the fair value of this derivative are reflected in operation and maintenance expenses and offset the benefits reflected above. Due to the extremely warm weather, protection instruments were not sufficient to offset approximately $3.1 million of the reduction in revenue for the six months ended March 31, 2012. There were no material effects on net income attributed to colder or warmer weather for the six months ended March 31, 2011.

Operation and Maintenance Expenses . The following table provides the key factors contributing to the changes in operation and maintenance expenses of the regulated utility for the six months ended March 31, 2012 compared to the same period in 2011.

Composition of Changes in Operation and Maintenance Expenses

(In millions)	Increase/ (Decrease)
Operations, engineering, construction and safety	$ 3.3
Employee benefits	2.7
Labor and incentive plans	2.1
Hexane costs	1.4
Weather derivative benefits:	
Benefit	(9.4)
Premium costs and fair value effects	(0.9)
Other operating expenses	0.4
Total	$ (0.4)

Operation, engineering, compliance and safety — The increase in operation, engineering, construction and safety costs during the six months ended March 31, 2012 compared to the same quarter of the prior year is primarily due to higher costs due to an increase in the volume of projects.

Employee benefits — The increase in benefit expenses reflects higher pension and other post-retirement benefits due to changes in discount rate and other plan assumptions used to measure the benefit obligation and higher reserve adjustments for long-term disability.

Labor and incentives — The increase in labor and incentive plans is primarily due to higher direct labor costs driven by higher long-term incentive plan valuations and general wage increases.

Hexane costs — The increase in expense during the six months ended March 31, 2012 compared to the same period of the prior year reflects the deferral of costs in 2011 to a regulatory asset under the regulatory mechanism that was in existence at the time.

Weather derivative benefits — The effects of hedging variations from normal weather in the District of Columbia for the six months ended March 31, 2012 and 2011 are recorded to operation and maintenance expense. Washington Gas recorded a gain of $6.3 million as a direct result of warmer than normal weather in the six months ended March 31, 2012 and a loss of $3.1 million during the six months ended March 31, 2011 due to colder-than-normal weather during that period. The benefits or losses of the weather-related instruments are generally offset by the effect of weather on utility net revenues; however, during the six months ended March 31, 2012, the warmer than normal weather exceeded the level of our hedging protection. In addition, net premiums received related to the weather derivatives were higher due to market expectations of weather.

Depreciation and Amortization — The increase of $2.7 million in depreciation and amortization is primarily attributed to growth in, and changes in the asset mix of, our investment in utility plant partially offset by a reduction in Virginia depreciation rates.

Retail Energy-Marketing

The following table depicts the retail energy-marketing segment's operating results along with selected statistical data.

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Retail-Energy Marketing Financial and Statistical Data

	Six Months Ended March 31, **2012**	2011	Increase / (Decrease)
Operating Results *(In millions)*			
Gross margins:			
Operating revenues	**$ 704.8**	$ 827.1	$ (122.3)
Less: Cost of energy	**663.4**	738.8	(75.4)
Revenue taxes	**2.7**	2.5	0.2
Total gross margins	**38.7**	85.8	(47.1)
Operation expenses	**27.4**	25.3	2.1
Depreciation and amortization	**0.4**	0.3	0.1
General taxes and other assessments—other	**2.0**	2.3	(0.3)
Operating income	**8.9**	57.9	(49.0)
Interest expense	**—**	0.1	(0.1)
Income tax expense	**3.6**	23.2	(19.6)
Net income	**$ 5.3**	$ 34.6	$ (29.3)
Analysis of gross margins *(In millions)*			
Natural gas			
Realized margins	**$ 17.9**	$ 22.3	$ (4.4)
Unrealized mark-to-market gains (losses)	**(7.8)**	12.8	(20.6)
Total gross margins — natural gas	**10.1**	35.1	(25.0)
Electricity			
Realized margins	**42.7**	30.3	12.4
Unrealized mark-to-market gains (losses)	**(14.1)**	20.4	(34.5)
Total gross margins — electricity	**28.6**	50.7	(22.1)
Total gross margins	**$ 38.7**	$ 85.8	$ (47.1)
Other Retail-Energy Marketing Statistics			
Natural gas			
Therm sales *(millions of therms)*	**432.4**	518.9	(86.5)
Number of customers *(end of period)*	**179,000**	173,400	5,600
Electricity			
Electricity sales *(millions of kWhs)*	**5,409.0**	5,057.4	351.6
Number of accounts *(end of period)*	**197,000**	183,700	13,300

The retail energy-marketing segment reported net income of $5.3 million for the six months ended March 31, 2012, compared to net income of $34.6 million reported for the same six-month period of the prior fiscal year.

The reduction in net income primarily reflects lower gross margins from electric and natural gas sales. Period-to-period comparisons of gross margins for this segment can vary significantly and are not necessarily representative of expected annualized results.

Gross margins from natural gas sales decreased $25.0 million in the current quarter of fiscal year 2012 when compared to the same quarter in the prior fiscal year. This decrease is primarily due to the unfavorable change in unrealized mark-to-market margins on energy-related derivatives of $20.6 million resulting from fluctuating market prices and $4.4 million in lower realized margins reflecting lower retail sales volumes resulting from warmer weather, and lower margins on portfolio optimization activities.

Gross margins from electric sales in the current quarter decreased $22.1 million from the same quarter of the prior period. This decrease reflects a $34.5 million change in unrealized mark-to-market margins on energy-related derivatives from fluctuating market prices partially offset by $12.4 million in higher realized margins attributable to favorable price conditions, higher sales volumes due to customer growth and a more favorable pattern of margin recognition in the current period versus the same period of the prior year.

The retail energy-marketing segment's increase in new electricity customer accounts compared to the prior year is primarily due to WGEServices being able to offer customers lower prices than utility standard offer service rates and the addition of new government and commercial accounts.

Commercial Energy Systems

The commercial energy systems segment reported net income of $0.8 million for the six months ended March 31, 2012, compared to a net loss of $20,000 reported for the same period of fiscal year 2011. This increase is due to higher revenue from commercial solar projects in the current period and the commencement of project work for government agency customers that was delayed in the prior year.

Wholesale Energy Solutions

The wholesale energy solutions segment reported net income of $2.5 million for the six months ended March 31, 2012, compared to net income of $0.2 million reported for the same period of the prior fiscal year. This increase is primarily due to the growth in asset optimization activity.

Other Non-Utility

Transactions that are not significant enough on a stand-alone basis to warrant treatment as an operating segment, and that do not fit into one of our four operating segments, are aggregated as "Other Activities" and included as part of non-utility operations. Results from our other non-utility activities reflect net losses of $0.8 million and $1.6 million for the six months ended March 31, 2012 and 2011, respectively.

LIQUIDITY AND CAPITAL RESOURCES

General Factors Affecting Liquidity

It is important for us to have access to short-term debt markets to maintain satisfactory liquidity to operate our businesses on a near-term basis. Our most significant short-term financing requirements include the acquisition of natural gas, electricity and pipeline capacity, and the need to finance accounts receivable and storage gas inventory. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt.

Our ability to obtain adequate and cost effective financing depends on our credit ratings, the liquidity of financial markets, and investor demand for our securities. Our credit ratings depend largely on the financial performance of our subsidiaries, and a downgrade in our current credit ratings could require us to post additional collateral with our wholesale counterparties and adversely affect our borrowing costs, as well as our access to sources of liquidity and capital. Also potentially affecting access to short-term debt capital is the nature of any restrictions that might be placed upon us, such as ratings triggers or a requirement to provide creditors with additional credit support in the event of a determination of insufficient creditworthiness. During the three months ended March 31, 2012, WGL Holdings met its liquidity and capital needs through the retention of earnings and the issuance of commercial paper and common stock. Washington Gas met its liquidity and capital needs through the retention of earnings and the issuance of commercial paper. Both WGL Holdings and Washington Gas believe that they will be able to meet their liquidity and capital needs through fiscal year 2012 through a mixture of operating earnings, issuances of commercial paper, and in the case of Washington Gas, issuance of MTNs.

We have a goal to maintain our common equity ratio in the mid-50% range of total consolidated capital. The level of this ratio varies during the fiscal year due to the seasonal nature of our business. This seasonality is also evident in the variability of our short-term debt balances, which are typically higher in the fall and winter months and substantially lower in the spring when a significant portion of our current assets are converted into cash at the end of the winter heating season. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings for WGL Holdings and Washington Gas, and to allow access to capital at reasonable costs. As of March 31, 2012, total consolidated capitalization, including current maturities of long-term debt and excluding notes payable, comprised 66.9% common equity, 1.5% preferred stock and 31.6% long- term debt. Our cash flow requirements and our ability to provide satisfactory resources to meet those requirements are primarily influenced by the activities of Washington Gas and WGEServices and, to a lesser extent, other non-utility operations.

Our plans provide for sufficient liquidity to satisfy our financial obligations. At March 31, 2012, we did not have any restrictions on our cash balances or retained earnings that would affect the payment of common or preferred stock dividends by WGL Holdings or Washington Gas.

Short-Term Cash Requirements and Related Financing

Washington Gas' business is weather sensitive and seasonal, causing short-term cash requirements to vary significantly during the year. Approximately 74% of the total therms delivered in Washington Gas' service area (excluding deliveries to two electric generation facilities) occur during the first and second fiscal quarters. Accordingly, Washington Gas typically generates more net income in the first six months of the fiscal year than it does for the entire fiscal year.

During the first six months of our fiscal year, Washington Gas generates large sales volumes and its cash requirements peak when combined storage inventory, accounts receivable, and unbilled revenues are at their highest levels. During the last six months of our fiscal year, after the winter heating season, Washington Gas will typically experience a seasonal net loss due to reduced demand for natural gas. During this period, many of Washington Gas' assets are converted into cash, which Washington Gas generally uses to reduce and sometimes eliminate short-term debt and to acquire storage gas for the next heating season.

Washington Gas, WGEServices and CEV have seasonal short-term cash requirements to fund the purchase of storage gas inventory in advance of the winter heating periods when a large portion of the storage gas is sold. At March 31, 2012 and September 30, 2011, Washington Gas had balances in gas storage of $66.9 million and $166.1 million, respectively; WGEServices had balances in gas storage of $15.5 million and $61.0 million, respectively, and CEV had balances in gas storage of $93.3 million and $63.3 million, respectively. Washington Gas collects the cost of gas under cost recovery mechanisms approved by its regulators. WGEServices and CEV collect revenues that are designed to reimburse their commodity costs used to supply their retail customer and wholesale counterparty contracts. Variations in the timing of cash receipts from customers under these collection methods can significantly affect short-term cash requirements. In addition, Washington Gas, WGEServices and CEV pay their respective commodity suppliers before collecting the accounts receivable balances resulting from these sales. WGEServices and CEV derive their funding to finance these activities from short-term debt issued by WGL Holdings. Additionally, Washington Gas, WGEServices and CEV may be required to post cash collateral for certain purchases. WGEServices and CEV may be required to provide parent guarantees from WGL Holdings for certain non-utility purchases.

Variations in the timing of collections of gas costs under Washington Gas' gas cost recovery mechanisms can significantly affect short-term cash requirements. At March 31, 2012 and September 30, 2011, Washington Gas had a $2.8 million and $12.1 million net under-collection of unrecovered gas costs, respectively, reflected in current assets/liabilities as gas costs due from/to customers related to the most recent twelve month gas cost recovery cycle ended August 31 of each year. Most of this balance will be collected from customers in fiscal year 2012. Amounts under-collected or over-collected that are generated during the current gas cost recovery cycle are deferred as a regulatory asset or liability on the balance sheet until September 1st of each year, at which time the accumulated amount is transferred to gas costs due from/to customers as appropriate. At March 31, 2012 and September 30, 2011, Washington Gas had a net regulatory liability of $1.8 million and net regulatory asset of $6.5 million, respectively, related to the current gas recovery cycle.

WGL Holdings and Washington Gas utilize short-term debt in the form of commercial paper or unsecured short-term bank loans to fund seasonal cash requirements. Our policy is to maintain back-up bank credit facilities in an amount equal to or greater than our expected maximum commercial paper position. Bank credit balances available to WGL Holdings and Washington Gas net of commercial paper balances were $268.1 million and $300.0 million at March 31, 2012 and $360.6 million and $300.0 million at September 30, 2011, respectively. On April 3, 2012, WGL Holdings and Washington Gas each entered into separate revolving credit agreements to replace the existing revolving credit agreements which were due to expire on August 2012. The credit facility for WGL Holdings permits it to borrow up to $450 million, and further permits, with the banks' approval, additional borrowings of $100 million for a maximum potential total of $550 million. The credit facility for Washington Gas permits it to borrow up to $350 million, and further permits, with the banks' approval, additional borrowings of $100 million for a maximum potential total of $450 million. The interest rate on loans made under each of the credit facilities will be a fluctuating rate per annum that will be set using certain parameters at the time each loan is made. These credit agreements provide for a term of five years and expire on April 3, 2017. The credit agreements each have two one-year extension options. Refer to Note 3 —*Short-Term Debt* of the Notes to the Consolidated Financial Statements for further information.

To manage credit risk, Washington Gas, WGEServices and CEV may require deposits from certain customers and suppliers, which are reported as current liabilities in "Customer deposits and advance payments," in the accompanying balance sheet. At March 31, 2012 and September 30, 2011, "Customer deposits and advance payments" totaled $70.6 million and $78.1 million, respectively. For both periods, almost all of these deposits related to customer deposits for Washington Gas.

For Washington Gas, deposits from customers may be refunded to the depositor-customer at various times throughout the year based on the customer's payment habits. At the same time, other customers make new deposits that cause the balance of customer deposits to remain relatively steady. There are no restrictions on Washington Gas' use of these customer deposits. Washington Gas pays interest to its customers on these deposits in accordance with the requirements of its regulatory commissions.

For WGEServices and CEV, deposits typically represent collateral for transactions with wholesale counterparties. These deposits may be required to be repaid or increased at any time based on the current value of WGEServices' net position with the counterparty. Currently there are no restrictions on the use of deposited funds and interest is paid to the counterparty on these deposits in accordance with its contractual obligations. Refer to the section entitled "Credit Risk" for further discussion of our management of credit risk.

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Long-Term Cash Requirements and Related Financing

The primary drivers of our long-term cash requirements include capital expenditures, long-term debt maturities, and decisions to refinance long-term debt. Our capital expenditures primarily relate to adding new utility customers and system supply as well as maintaining the safety and reliability of Washington Gas' distribution system. Refer to our 2011 Annual Report for a discussion of our long-term debt maturities and capital expenditures.

On February 27, 2012, Washington Gas retired $25.0 million of 6.0% MTNs. Previously during the year, on October 17 and 19, 2011, Washington Gas retired $7.0 million of 6.05% MTNs and $20.0 million of 6.00% MTNs, respectively. At March 31, 2012, Washington Gas had the capacity under a shelf registration to issue up to $375 million of additional MTNs. Washington Gas has authority from its regulators to issue other forms of debt, including private placements.

We are exposed to interest-rate risk associated with our debt financing. Prior to issuing long-term debt, Washington Gas may utilize derivative instruments to minimize its exposure to the risk of interest-rate volatility. Refer to the section entitled " *Interest-Rate Risk* " included in Management's Discussion for further discussion of our interest-rate risk management activity.

Security Ratings

The table below reflects the current credit ratings for the outstanding debt instruments of WGL Holdings and Washington Gas. Changes in credit ratings may affect WGL Holdings' and Washington Gas' cost of short-term and long-term debt and their access to the capital markets. A security rating is not a recommendation to buy, sell or hold securities. The rating may be subject to revision or withdrawal at any time by the assigning rating organization and each rating should be evaluated independently of any other rating.

Credit Ratings for Outstanding Debt Instruments

	WGL Holdings		**Washington Gas**	
Rating Service	Unsecured Medium-Term Notes (Indicative) [(a)]	Commercial Paper	Unsecured Medium- Term Notes	Commercial Paper
Fitch Ratings [(b)]	A+	F1	AA–	F1+
Moody's Investors Service [(c)]	Not Rated	P-2	A2	P-1
Standard & Poor's Ratings Services [(d)]	A+	A-1	A+	A-1

(a) Indicates the ratings that may be applicable if WGL Holdings were to issue unsecured MTNs.
(b) The long-term debt ratings outlook issued by Fitch Ratings for WGL Holdings and Washington Gas is stable.
(c) The long-term debt ratings outlook issued by Moody's Investors Service for Washington Gas is stable.
(d) The long-term debt ratings outlook issued by Standard & Poor's Rating Services for WGL Holdings and Washington Gas is stable.

Ratings Triggers and Certain Debt Covenants

WGL Holdings and Washington Gas pay fees on their credit facilities, which in some cases are based on the long-term debt ratings of Washington Gas. In the event the long-term debt of Washington Gas is downgraded below certain levels, WGL Holdings and Washington Gas would be required to pay higher fees. There are five different levels of fees. The credit facility for WGL Holdings defines its applicable fee level as one level below the level applicable to Washington Gas. Under the terms of the credit facilities, the lowest level facility fee is 6.0 basis points and the highest is 17.5 basis points.

Under the terms of WGL Holdings' and Washington Gas' credit agreements, the ratio of consolidated financial indebtedness to consolidated total capitalization cannot exceed 0.65 to 1.0 (65.0%). In addition, WGL Holdings and Washington Gas are required to inform lenders of changes in corporate existence, financial conditions, litigation, and environmental warranties that might have a material effect. The failure to inform the lenders' agent of changes in these areas deemed material in nature might constitute default under the agreements. Additionally, failure to pay principal or interest on any other indebtedness may be deemed a default under our credit agreements. A default, if not remedied, may lead to a suspension of further loans and/or acceleration in which obligations become immediately due and payable. At March 31, 2012, we were in compliance with all of the covenants under our revolving credit facilities.

For certain of Washington Gas' natural gas purchase and pipeline capacity agreements, if the long-term debt of Washington Gas is downgraded to or below the lower of a BBB- rating by Standard & Poor's or a Baa3 rating by Moody's Investors Service, or if Washington Gas is deemed by a counterparty not to be creditworthy, then the counterparty may withhold service or deliveries, or may require additional credit support. For certain other agreements, if the counterparty's credit exposure to Washington Gas exceeds a contractually defined threshold amount, or if Washington Gas' credit rating declines, then the counterparty may require additional credit support. At March 31, 2012, Washington Gas would not be required to supply additional credit support by these arrangements if its long-term debt rating was to be downgraded one rating level.

WGL Holdings has guaranteed payments for certain purchases of natural gas and electricity on behalf of its wholly-owned subsidiaries; WGEServices and CEV (refer to our 2011 Annual Report for a further discussion of these guarantees). If the credit rating of WGL Holdings declines, WGEServices and CEV may be required to provide additional credit support for these purchase contracts. At March 31, 2012, neither WGEServices nor CEV would be required to provide additional credit support, for these arrangements if the long-term debt rating of WGL Holdings was to be downgraded one rating level.

Cash Flows Provided by Operating Activities

The primary drivers for our operating cash flows are cash payments received from natural gas and electricity customers, offset by our payments for natural gas and electricity costs, operation and maintenance expenses, taxes and interest costs.

Net cash provided by operating activities totaled $207.9 million for the six months ended March 31, 2012. Net cash provided by operating activities reflects net income before preferred stock dividends, as adjusted for non-cash earnings and charges and changes in working capital including:

- Accounts receivable and unbilled revenues—net increased $206.0 million from September 30, 2011, primarily due to increased sales volumes to customers during our winter heating season and increased sales volumes associated with Washington Gas' asset optimization program.
- Storage gas inventory cost levels decreased $114.7 million from September 30, 2011 primarily due to conversion to cash through seasonal physical withdrawals.
- Gas costs (current and deferred) and other regulatory assets / liabilities—net decreased $38.6 million from September 30, 2011 primarily due to decreases in balancing charges and mark-to-market adjustments.
- Accounts payable and other accrued liabilities decreased $10.1 million, due to lower gas prices, partially offset by a seasonal increase in the volumes of natural gas purchases and increased trading activity in CEV. Volumes increased both for deliveries to customers for the winter heating season and for Washington Gas' asset optimization program.
- Accrued taxes increased $52.2 million from September 30, 2011 primarily due to an increase in fuel taxes in Maryland and the District of Columbia.
- Other current assets increased $55.4 million primarily due to net changes in the valuation of energy related derivative contracts.
- Other current liabilities decreased $35.7 million primarily due to net changes in the valuation of energy related derivative contracts.

Cash Flows Provided by Financing Activities

Cash flows provided by financing activities totaled $3.2 million for the six months ended March 31, 2012, reflecting the issuance of $92.5 million of notes payable, partially offset by the retirement of $52.0 million of long-term debt and dividends on common and preferred stock of $37.9 million.

Cash Flows Used in Investing Activities

During the six months ended March 31, 2012, cash flows used in investing activities totaled $118.3 million, which primarily consists of capital expenditures made on behalf of Washington Gas. In addition, investing activities also reflects additional investments in commercial Solar Photovoltaic (Solar PV) facilities and investments in a partnership to directly fund residential Solar PV facilities.

CONTRACTUAL OBLIGATIONS, OFF-BALANCE SHEET ARRANGEMENTS AND OTHER COMMERCIAL COMMITMENTS

Contractual Obligations

We have certain contractual obligations incurred in the normal course of business that require us to make fixed and determinable payments in the future. These commitments include long-term debt, lease obligations, unconditional purchase obligations for pipeline capacity, transportation and storage services, certain natural gas and electricity commodity commitments and our commitments related to the BPO program.

Reference is made to the *"Contractual Obligations, Off-Balance Sheet Arrangements and Other Commercial Commitments"* section of Management's Discussion in our 2011 Annual Report for a detailed discussion of our contractual obligations. Note 4 of the Notes to Consolidated Financial Statements in our 2011 Annual Report includes a discussion of long-term debt, including debt maturities. Note 13 of the Notes to Consolidated Financial Statements in our 2011 Annual Report reflects information about the various contracts of Washington Gas, WGEServices and CEV. Additionally, refer to Note 13 of the Notes to Consolidated Financial Statements in this quarterly report.

There have been no significant changes to contractual obligations in the three month period ended March 31, 2012.

Construction Project Financing

To fund certain of its construction projects, Washington Gas enters into financing arrangements with third party lenders. As part of these financing arrangements, Washington Gas' customers agree to make principal and interest payments over a period of time, typically beginning after the projects are completed. Washington Gas assigns these customer payment streams to the lender. As the lender funds the construction project, Washington Gas establishes a receivable representing its customers' obligations to remit principal and interest and a long-term payable to the lender. When these projects are formally "accepted" by the customer as completed, Washington Gas transfers the ownership of the receivable to the lender and removes both the receivable and the long-term financing from its financial statements. As of March 31, 2012 and September 30, 2011, work on these construction projects that was not completed or accepted by customers was valued at $2.8 million and $4.2 million, respectively, which are recorded on the balance sheet as a receivable in "Deferred Charges and Other Assets—Other" with the corresponding long-term obligation to the lender in "Long-term debt." At any time before these contracts are accepted by the customer, should there be a contract default, such as, among other things, a delay in completing the project, the lender may call on Washington Gas to fund the unpaid principal in exchange for which Washington Gas would receive the right to the stream of payments from the customer. Construction projects are financed primarily for government agencies, which Washington Gas considers to have minimal credit risk. Based on this assessment and previous collection experience, Washington Gas did not record a corresponding reserve for bad debts related to these receivables at March 31, 2012 and September 30, 2011.

Financial Guarantees

WGL Holdings has guaranteed payments primarily for certain purchases of natural gas and electricity on behalf of WGEServices and for certain purchase commitments on behalf of CEV. At March 31, 2012, these guarantees totaled $532.5 million and $122.6 million for WGEServices and CEV, respectively. The amount of such guarantees is periodically adjusted to reflect changes in the level of financial exposure related to these purchase commitments. We also receive financial guarantees or other collateral from counterparties when required by our credit policy (refer to the section entitled *"Credit Risk"* for a further discussion of our credit policy). WGL Holdings also issued guarantees totaling $3.0 million at March 31, 2012 on behalf of certain of our non-utility subsidiaries associated with their banking transactions. Of the total guarantees of $658.1 million, $4.8 million expired on April 30, 2012, and $22.2 million is due to expire on October 31, 2012. The remaining guarantees do not have specific maturity dates. For all of its financial guarantees, WGL Holdings may cancel any or all future obligations imposed by the guarantees upon written notice to the counterparty, but WGL Holdings would continue to be responsible for the obligations created under the guarantees prior to the effective date of the cancellation.

Effective October 1, 2011, WGL Holdings began charging to its subsidiaries guarantee fees in an amount equal to the daily guarantee exposure multiplied by a monthly weighted average interest rate. During the three and six months ended March 31, 2012, the total fees charged by WGL Holdings to its subsidiaries were $0.2 million and $0.3 million, respectively. The majority of these fees were charged to WGEServices and have been eliminated in the accompanying consolidated financial statements of WGL Holdings.

Chillum LNG Facility

Washington Gas continues to incorporate in its plans construction of a proposed one billion cubic foot liquefied natural gas (LNG) storage facility on the land owned by Washington Gas in Chillum, Maryland, where natural gas storage facilities previously existed for meeting customers' forecasted peak demand for natural gas. Subject to the resolution of certain legal and regulatory issues, the new storage facility is currently expected to be completed and in service by the 2019-2020 winter heating season at a total estimated cost of $185.3 million.

In 2005, Washington Gas requested approval from the Maryland Public Service Commission (PSC of MD) regarding the safety of the proposed facility and compliance with applicable federal regulations. In 2007, the Engineering Division of the PSC of MD confirmed the analysis that had been presented by Washington Gas and found the proposed facility to be safely sited. On March 19, 2009, the PSC of MD docketed a proceeding for the purpose of reviewing Washington Gas' most recent gas procurement plan including the role the Chillum facility plays in meeting current and future customers' annual and seasonal natural gas requirements.

On October 30, 2006, the District Council of Prince George's County, Maryland denied Washington Gas' application for a special exception related to its proposed construction of the LNG peaking plant because of the District Council's position that newly enacted zoning restrictions prohibit such construction. Washington Gas appealed this decision to the Prince George's County Circuit Court (the Circuit Court) on November 22, 2006; however, the case was subsequently sent back to the administrative process by the Circuit Court. On April 16, 2008, Washington Gas filed a Complaint for Declaratory and Injunctive Relief with the United States District Court for the District of Maryland (the U.S. District Court) seeking a declaratory judgment that all local laws relating to safety and location of the facility are preempted by Federal and State law. On March 26, 2010, the U.S. District Court denied Washington Gas' motion for summary judgment; however, Washington Gas filed an amended complaint and there have been further proceedings for consideration of the preemption issues raised by Washington Gas. On March 9, 2012, the U.S. District Court issued an order and memorandum opinion that denied Washington Gas' motion for summary judgment. Washington Gas filed a notice of appeal with the U.S. Circuit Court of Appeals for the Fourth Circuit on April 3, 2012.

Washington Gas must begin construction of the storage facility in the spring of 2016 in order for the Chillum Facility to be completed and in service by the 2019-2020 winter heating season. Until the LNG plant is constructed, Washington Gas has planned for alternative sources of supply to meet its customers' peak day requirements. These plans include capital expenditures related to infrastructure improvements which contribute to providing for adequate system performance based on projected needs.

Operating Issues Related To Changes In Natural Gas Supply

In fiscal year 2005, Washington Gas began addressing a significant increase in the number of natural gas leaks on its distribution system in a portion of Prince George's County, Maryland. Natural gas containing a low concentration of heavy hydrocarbons (HHCs) can cause the seals in certain mechanical couplings on the Washington Gas distribution system to shrink increasing the propensity for the coupling to leak. Independent laboratory tests performed on behalf of Washington Gas have shown that, in a laboratory environment, the injection of HHCs into gas with low concentrations of HHC can be effective in offsetting the affect of the low HHC gas on the seals in couplings which increases their sealing force and in turn, reduces the propensity for the affected couplings to leak.

To resolve the significant increase in leaks, Washington Gas replaced gas service lines and replaced or rehabilitated gas mains that contained the affected mechanical couplings in Prince George's County. Additionally, Washington Gas constructed three facilities to inject HHCs into the gas stream entering the Washington Gas distribution system. Washington Gas has been evaluating the effectiveness of this HHC injection process on the affected couplings under field conditions. Our evaluation of the role of these HHC injections as a preventative and remedial measure was filed in a report to the PSC of MD on June 29, 2007. Washington Gas continues to mitigate the impact of low HHC gas from whatever source through accelerating the replacement of mechanically coupled pipeline and the operation of three HHC injection facilities.

The current planned mechanical coupling remediation and replacement work includes a planned $62.0 million, 5-year, mechanically coupled pipe replacement program approved by the SCC of VA on April 21, 2011 as part of Washington Gas' SAVE filing and the continuation of the December 16, 2009 settlement in the District of Columbia that includes a targeted mechanically coupled pipe replacement and encapsulation program which is estimated to cost $28.0 million and is expected to take approximately seven years to complete. Rate recovery of the expenditures has been approved by the SCC of VA and the PSC of DC. Additionally, Washington Gas has budgeted approximately $47.0 million related to a planned 5-year mechanically coupled pipe replacement program in Maryland.

Additional operating expenses and capital expenditures may be necessary to contend with leaks that may accompany the receipt of increased volumes of low HHC gas into Washington Gas' distribution system. Such additional operating expenses and capital expenditures may not be timely enough to mitigate the challenges posed by increased volumes of low HHC gas, potentially resulting in leakage from mechanical couplings at a rate that could compromise the safety of our distribution system.

Notwithstanding Washington Gas' recovery of costs related to the construction of the injection facilities and hexane costs through local regulatory commission action, Washington Gas has pursued and will pursue all remedies available to keep its customers from having to pay more than their appropriate share of the costs of the remediation to maintain the safety of the Washington Gas distribution system.

Commonwealth Pipeline

In February 2012, CEV entered into a joint development agreement with UGI Energy Services, Inc. (UGI) and Inergy Midstream, L.P. (Inergy), to jointly market and develop a 200-mile interstate pipeline named the Commonwealth Pipeline. The pipeline is planned to extend south from the terminus of Inergy's Marc I line in Lycoming County, Pennsylvania and run through central and eastern Pennsylvania accessing markets in and around Philadelphia, Baltimore and the Washington, D.C. metropolitan region. The new pipeline will provide these markets with direct access to abundant supplies of Marcellus natural gas through a safe, reliable and cost-effective transportation system. The pipeline is expected to cross and link with a number of interstate pipelines along its route, providing even greater supply diversity to the mid-Atlantic region while simultaneously providing Marcellus producers with direct access to expanding markets currently served by legacy interstate pipelines.

The purpose of the joint development agreement is to determine the commercial, financial and engineering feasibility and viability of developing the interstate pipeline. The joint development agreement also defines the rights and obligations of each party with respect to the preliminary development and marketing of the interstate pipeline. CEV and UGI are expected to execute precedent agreements to become anchor shippers on the pipeline.

If the parties agree to construct the pipeline after analyzing and assessing certain development considerations, the pipeline is expected to go into service in 2015 and transport at least 800,000 dekatherms of natural gas per day. CEV, Inergy and UGI expect to be equal equity holders of the project. Inergy will construct and operate the pipeline which is expected to cost approximately $1.0 billion and be funded equally by the three parties. To date, no capital expenditures have been incurred on the project and the company has recorded its expenses associated with marketing and development activities.

CREDIT RISK

Wholesale Credit Risk

Certain wholesale suppliers that sell natural gas to any or all of Washington Gas, WGEServices, and CEV may have relatively low credit ratings or may not be rated by major credit rating agencies.

Washington Gas enters into transactions with wholesale counterparties for the purpose of meeting firm ratepayer commitments, to optimize the value of its long-term capacity assets, and for hedging natural gas costs. In the event of a counterparty's failure to deliver contracted volumes of gas or fulfill its payment obligations, Washington Gas may incur losses that would typically be passed through to its sales customers under the purchased gas cost adjustment mechanisms. Washington Gas may be at risk for financial loss to the extent these losses are not passed through to its customers.

For WGEServices, any failure of wholesale counterparties to deliver natural gas or electricity under existing contracts could cause financial exposure for the difference between the price at which WGEServices has contracted to buy these commodities and their replacement cost from another supplier. To the extent that WGEServices sells natural gas to these wholesale counterparties, WGEServices may be exposed to payment risk if WGEServices is in a net receivable position. Additionally, WGEServices enters into contracts with third parties to hedge the costs of natural gas and electricity. Depending on the ability of the third parties to fulfill their commitments, WGEServices could be at risk for financial loss.

CEV enters into transactions with wholesale counterparties to optimize its portfolio of owned and managed natural gas assets. Any failure of wholesale counterparties to deliver natural gas under existing contracts could cause financial exposure for the difference between the price at which CEV has contracted to buy these commodities and their replacement cost. To the extent that CEV sells natural gas to these wholesale counterparties, CEV may be exposed to payment risk if it is in a net receivable position. In addition, CEV enters into contracts with third parties to hedge the costs of natural gas. Depending on the ability of the third parties to fulfill their commitments, CEV could be at risk for financial loss.

Washington Gas, WGEServices and CEV have an existing credit policy that is designed to mitigate credit risks through a requirement for credit enhancements including, but not limited to, letters of credit, parent guarantees and cash collateral when deemed necessary. In accordance with this policy, Washington Gas, WGEServices and CEV have each obtained credit enhancements from certain of their counterparties. If certain counterparties or their guarantors meet the policy's credit worthiness criteria, Washington Gas, WGEServices and CEV may grant unsecured credit to those counterparties or their guarantors. The credit worthiness of all counterparties is continuously monitored.

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Washington Gas, WGEServices and CEV are also subject to the collateral requirements of their counterparties. At March 31, 2012, Washington Gas, WGEServices and CEV provided $4.4 million, $0.3 million and $19.4 million in cash collateral to counterparties, respectively.

The following table provides information on our credit exposure, net of collateral, to wholesale counterparties as of March 31, 2012 for Washington Gas, WGEServices and CEV, separately.

Credit Exposure to Wholesale Counterparties (In millions)

Rating [(a)]	Exposure Before Credit Collateral [(b)]	Offsetting Credit Collateral Held [(c)]	Net Exposure	Number of Counterparties Greater Than 10% [(d)]	Net Exposure of Counterparties Greater Than 10%
Washington Gas					
Investment Grade	$ 9.6	$ —	$ 9.6	2	$ 5.2
Non-Investment Grade	6.2	5.0	1.2	1	1.2
No External Ratings	5.8	—	5.8	1	4.8
WGEServices					
Investment Grade	$ 0.1	$ —	$ 0.1	1	$ 0.1
Non-Investment Grade	—	—	—	—	—
No External Ratings	0.2	—	0.2	3	0.1
CEV					
Investment Grade	$ 7.8	$ —	$ 7.8	3	$ 6.1
Non-Investment Grade	—	—	—	—	—
No External Ratings	1.2	—	1.2	—	—

[(a)] *Included in "Investment Grade" are counterparties with a minimum Standard & Poor's or Moody's Investor Service rating of BBB- or Baa3, respectively. If a counterparty has provided a guarantee by a higher-rated entity (e.g., its parent), the guarantor's rating is used in this table.*

[(b)] *Includes the net of all open positions on energy-related derivatives subject to mark-to-market accounting requirements, the net receivable/payable for realized transactions and net open positions for contracts designated as normal purchases and normal sales and not recorded on our balance sheet. Amounts due from counterparties are offset by liabilities payable to those counterparties to the extent that legally enforceable netting arrangements are in place.*

[(c)] *Represents cash deposits and letters of credit received from counterparties, not adjusted for probability of default.*

[(d)] *Using a percentage of the net exposure.*

Retail Credit Risk

Washington Gas is exposed to the risk of non-payment of utility bills by certain of its customers. To manage this customer credit risk, Washington Gas may require cash deposits from its high risk customers to cover payment of their bills until the requirements for the deposit refunds are met. In addition, Washington Gas implemented a POR program as approved by the PSC of MD, whereby it purchases receivables from participating energy marketers at approved discount rates. Under the program, Washington Gas is exposed to the risk of non-payment by the retail customers for these receivables. This risk is factored into the approved discount rate at which Washington Gas purchases the receivables.

WGEServices is also exposed to the risk of non-payment by its retail customers. WGEServices manages this risk by evaluating the credit quality of certain new customers as well as by monitoring collections from existing customers. To the extent necessary, WGEServices can obtain collateral from, or terminate service to, its existing customers based on credit quality criteria. In addition, WGEServices participates in POR programs with certain Maryland and Pennsylvania utilities, whereby it sells its receivables to various utilities at approved discount rates. Under the POR programs, WGEServices is exposed to the risk of non-payment by its retail customers for delivered commodities that have not yet been billed. Once the invoices are billed, however, the associated credit risk is assumed by the purchasing utilities. While participation in POR programs reduce the risk of collection and fixes a discount rate on the receivables, there is a risk that the discount rate paid to participate in the POR program will exceed the actual bad debt expense and billing fees associated with these receivables.

CEV is not subject to retail credit risk.

MARKET RISK

We are exposed to various forms of market risk including commodity price risk, weather risk and interest-rate risk. The following discussion describes these risks and our management of them.

Price Risk Related to the Regulated Utility Segment

Washington Gas faces price risk associated with the purchase and sale of natural gas. Washington Gas generally recovers the cost of the natural gas to serve customers through gas cost recovery mechanisms as approved in jurisdictional tariffs; therefore, a change in the price of natural gas generally has no direct effect on Washington Gas' net income. However, Washington Gas is responsible for following competitive and reasonable practices in purchasing natural gas for its customers.

To manage price risk associated with its natural gas supply to its firm customers, Washington Gas: *(i)* actively manages its gas supply portfolio to balance sales and delivery obligations; *(ii)* injects natural gas into storage during the summer months when prices are historically lower, and withdraws that gas during the winter heating season when prices are historically higher and *(iii)* enters into hedging contracts and other contracts that qualify as derivative instruments related to the sale and purchase of natural gas.

Washington Gas executes commodity-related physical and financial contracts in the form of forwards, swaps and option contracts as part of an asset optimization program that is managed by its internal staff. These transactions are accounted for as derivatives. Under this program, Washington Gas realizes value from its long-term natural gas transportation and storage capacity resources when not being fully used to serve utility customers. Regulatory sharing mechanisms in all three jurisdictions allow the profit from these transactions to be shared between Washington Gas' customers and shareholders.

The following two tables summarize the changes in the fair value of our net assets (liabilities) associated with the regulated utility segment's energy-related derivatives during the six months ended March 31, 2012:

Regulated Utility Segment
Changes in Fair Value of Energy-Related Derivatives

(In millions)	
Net liabilities at September 30, 2011	$ (3.2)
Net fair value of contracts entered into during the period	28.3
Other changes in net fair value	4.9
Realized net settlement of derivatives	(18.3)
Net assets at March 31, 2012	$ 11.7

Regulated Utility Segment
Roll Forward of Energy-Related Derivatives

(In millions)	
Net liabilities at September 30, 2011	$ (3.2)
Recorded to income	7.6
Recorded to regulatory assets/liabilities	25.6
Realized net settlement of derivatives	(18.3)
Net assets at March 31, 2012	$ 11.7

The maturity dates of our net assets (liabilities) associated with the regulated utility segment's energy-related derivatives recorded at fair value at March 31, 2012, is summarized in the following table based on the level of the fair value calculation under ASC Topic 820:

Regulated Utility Segment
Maturity of Net Assets (Liabilities) Associated with our Energy-Related Derivatives

		Years Ended September 30,					
(In millions)	**Total**	Remainder 2012	2013	2014	2015	2016	Thereafter
Level 1 — Quoted prices in active markets	**$ —**	$ —	$ —	$ —	$ —	$ —	$ —
Level 2 — Significant other observable inputs	**16.3**	0.9	3.3	10.0	2.1	—	—
Level 3 — Significant unobservable inputs	**(4.6)**	(1.5)	(3.8)	(9.3)	1.9	3.5	4.6
Total net assets (liabilities) associated with our energy-related derivatives	**$11.7**	$ (0.6)	$ (0.5)	$ 0.7	$ 4.0	$ 3.5	$ 4.6

Refer to Note 9, *Derivative and Weather-Related Instruments* and Note 10, *Fair Value Measurements* of the Notes to Consolidated Financial Statements for a further discussion of our derivative activities and fair value measurements.

Price Risk Related to the Non-Utility Segments

Retail Energy Marketing. Our retail energy-marketing subsidiary, WGEServices, sells natural gas and electricity to retail customers at both fixed and indexed prices. WGEServices must manage daily and seasonal demand fluctuations for these products with its suppliers. Price risk exists to the extent WGEServices does not closely match the timing and volume of natural gas and electricity it purchases with the related fixed price or indexed sales commitments. WGEServices' risk management policies and procedures are designed to minimize this risk.

A portion of WGEServices' annual natural gas sales volumes is subject to variations in customer demand associated with fluctuations in weather and other factors. Purchases of natural gas to fulfill retail sales commitments are generally made under fixed-volume contracts based on certain weather assumptions. If there is significant deviation from normal weather or other factors which affect customer usage, purchase commitments may differ significantly from actual customer usage. To the extent that WGEServices cannot match its customer requirements and supply commitments, it may be exposed to commodity price and volume variances, which could negatively impact expected gross margins (refer to the section entitled " *Weather Risk* " for a further discussion of our management of weather risk). WGEServices manages these risks through the use of derivative instruments including financial products and wholesale supply contracts that provide for volumetric variability.

WGEServices procures electricity supply under contract structures in which WGEServices assumes the responsibility of matching its customer requirements with its supply purchases. WGEServices assembles the various components of supply, including electric energy from various suppliers, and capacity, ancillary services and transmission service from the PJM Interconnection, a regional transmission organization, to match its customer requirements in accordance with its risk management policy.

To the extent WGEServices has not sufficiently matched its customer requirements with its supply commitments, it could be exposed to electricity commodity price risk. WGEServices may manage this risk through the use of derivative instruments, including financial products.

WGEServices' electric business is also exposed to fluctuations in weather and varying customer usage. Purchases generally are made under fixed-price, fixed-volume contracts that are based on certain weather assumptions. If there are significant deviations in weather or usage from these assumptions, WGEServices may incur price and volume variances that could negatively impact expected gross margins (refer to the section entitled *"Weather Risk"* for a further discussion of our management of weather risk).

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The following two tables summarize the changes in the fair value of our net assets (liabilities) associated with the retail energy marketing segment's energy-related derivatives during the six months ended March 31, 2012:

Retail Energy Marketing Segment
Changes in Fair Value of Energy-Related Derivatives

(In millions)	
Net liabilities at September 30, 2011	$(21.4)
Net fair value of contracts entered into during the period	(4.6)
Other changes in net fair value	(45.7)
Realized net settlement of derivatives	27.2
Net liabilities at March 31, 2012	$(44.5)

Retail Energy Marketing Segment
Roll Forward of Energy-Related Derivatives

(In millions)	
Net liabilities at September 30, 2011	$(21.4)
Recorded to income	(49.1)
Recorded to accounts payable	(1.2)
Realized net settlement of derivatives	27.2
Net liabilities at March 31, 2012	$(44.5)

The maturity dates of our net assets (liabilities) associated with the retail energy marketing segments' energy-related derivatives recorded at fair value at March 31, 2012 is summarized in the following table based on the level of the fair value calculation under ASC Topic 820:

Retail Energy Marketing Segment
Maturity of Net Assets (Liabilities) Associated with our Energy-Related Derivatives

		Years Ended September 30,					
(In millions)	**Total**	Remainder 2012	2013	2014	2015	2016	Thereafter
Level 1 — Quoted prices in active markets	**$ —**	$ —	$ —	$ —	$ —	$ —	$ —
Level 2 — Significant other observable inputs	**(43.7)**	(19.1)	(18.4)	(5.9)	(0.3)	—	—
Level 3 — Significant unobservable inputs	**(0.8)**	(4.1)	(1.0)	3.7	0.6	—	—
Total net assets (liabilities) associated with our energy-related derivatives	**$(44.5)**	$ (23.2)	$(19.4)	$(2.2)	$ 0.3	$ —	$ —

Refer to Note 9, *Derivative and Weather-Related Instruments* and Note 10, *Fair Value Measurements* of the Notes to Consolidated Financial Statements for a further discussion of our derivative activities and fair value measurements.

Wholesale Energy Solutions. CEV engages in wholesale commodity transactions to optimize its owned and managed capacity assets. Depending upon the nature of its forward hedges, CEV may be exposed to fluctuations in mark-to-market valuations based on changes in forward price curves. Price risk exists to the extent that uneven physical natural gas volumes do not perfectly match with forward contracts.

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The following two tables summarize the changes in the fair value of our net assets (liabilities) associated with the non-utility segments' energy-related derivatives for both natural gas and electricity during the six months ended March 31, 2012:

Wholesale Energy Solutions Segment
Changes in Fair Value of Energy-Related Derivatives

(In millions)	
Net assets at September 30, 2011	$ 8.1
Net fair value of contracts entered into during the period	45.3
Other changes in net fair value	7.1
Realized net settlement of derivatives	(21.3)
Net assets at March 31, 2012	$ 39.2

Wholesale Energy Solutions Segment
Roll Forward of Energy-Related Derivatives

(In millions)	
Net assets at September 30, 2011	$ 8.1
Recorded to income	52.4
Realized net settlement of derivatives	(21.3)
Net assets at March 31, 2012	$ 39.2

The maturity dates of our net assets (liabilities) associated with the wholesale energy solutions segments' energy-related derivatives recorded at fair value at March 31, 2012 is summarized in the following table based on the level of the fair value calculation under ASC Topic 820:

Wholesale Energy Solutions Segment
Maturity of Net Assets (Liabilities) Associated with our Energy-Related Derivatives

		Years Ended September 30,					
(In millions)	**Total**	Remainder 2012	2013	2014	2015	2016	Thereafter
Level 1 — Quoted prices in active markets	**$ —**	$ —	$ —	$ —	$ —	$ —	$ —
Level 2 — Significant other observable inputs	**39.2**	(0.7)	39.1	0.8	—	—	—
Level 3 — Significant unobservable inputs	**—**	—	—	—	—	—	—
Total net assets associated with our energy-related derivatives	**$39.2**	$ (0.7)	$39.1	$ 0.8	$ —	$ —	$ —

Refer to Note 9, *Derivative and Weather-Related Instruments* and Note 10, *Fair Value Measurements* of the Notes to Consolidated Financial Statements for a further discussion of our derivative activities and fair value measurements.

Value-at-Risk. WGEServices measures the market risk of its energy commodity portfolio by determining its value-at-risk. Value-at-risk is an estimate of the maximum loss that can be expected at some level of probability if a portfolio is held for a given time period. The value-at-risk calculation for natural gas and electric portfolios include assumptions for normal weather, new customers and renewing customers for which supply commitments have been secured. Based on a 95% confidence interval for a one-day holding period, WGEServices' value-at-risk at March 31, 2012 was approximately $4,000 and $48,000, related to its natural gas and electric portfolios, respectively.

Weather Risk

We are exposed to various forms of weather risk in both our regulated utility and non-utility business segments. To the extent Washington Gas does not have weather derivatives or billing adjustment mechanisms in place, its revenues are volume driven and its current rates are based upon an assumption of normal weather. Without weather protection strategies, variations from normal weather will cause our earnings to increase or decrease depending on the weather pattern. Washington Gas currently has a weather protection strategy that is designed to neutralize the estimated financial effects of weather on its net income within a reasonable range of weather expectations, as discussed below.

The financial results of our retail energy-marketing business, WGEServices, are affected by variations from normal weather primarily in the winter relating to its natural gas sales, and throughout the fiscal year relating to its electricity sales. WGEServices manages these weather risks with, among other things, weather derivatives.

Variations from normal weather may also affect the financial results of our wholesale energy business, CEV, primarily with regards to summer—winter storage spreads and in transportation spreads throughout the fiscal year. CEV manages these weather risks with, among other things, locational physical and financial basis hedging.

Billing Adjustment Mechanisms. In Maryland, Washington Gas has an RNA billing mechanism that is designed to stabilize the level of net revenues collected from Maryland customers by eliminating the effect of deviations in customer usage caused by variations in weather from normal levels and other factors such as conservation. In Virginia, Washington Gas has a Weather Normalization Adjustment (WNA) billing adjustment mechanism that is designed to eliminate the effect of variations in weather from normal levels on utility net revenues. Additionally, as part of the CARE, Washington Gas has a CRA mechanism, which, coupled with the WNA, eliminates the effect of both weather and other factors such as conservation for residential customers in Virginia. For a discussion of current rates and regulatory matters, refer to the section entitled "Rates and Regulatory Matters" in Management's Discussion for Washington Gas.

For the RNA, WNA, and CRA mechanisms, periods of colder-than-normal weather generally would cause Washington Gas to record a reduction to its revenues and establish a refund liability to customers, while the opposite would generally result during periods of warmer-than-normal weather. However, factors such as volatile weather patterns and customer conservation may cause the RNA and the CARE adjustment to function conversely because they adjust billed revenues to provide a designed level of net revenue per meter.

Weather Derivatives. On August 12, 2011, Washington Gas executed HDD weather derivative contracts to manage its financial exposure to variations from normal weather in the District of Columbia for fiscal year 2012 resulting in a net premium payment to Washington Gas of $0.8 million. Under these contracts, Washington Gas purchased protections against net revenue shortfalls due to warmer-than-normal weather and sold colder-than-normal weather benefits. Because weather during the first six months of fiscal year 2012 was extraordinarily warm, Washington Gas expects to receive the maximum contractual payment of $7.1 million (including the net premium) from its weather derivatives. This amount is not expected to be sufficient to cover all of Washington Gas' warm-weather exposure in the District of Columbia.

WGEServices utilizes HDD derivatives from time to time to manage weather risks related to its natural gas and electricity sales. WGEServices also utilizes cooling degree day (CDD) derivatives to manage weather risks related to its electricity sales during the summer cooling season. These derivatives cover a portion of WGEServices' estimated revenue or energy-related cost exposure to variations in HDDs or CDDs. Refer to Note 9 —*Derivatives* of the Notes to Consolidated Financial Statements for a further discussion of the accounting for these weather-related instruments.

Interest-Rate Risk

We are exposed to interest-rate risk associated with our short-term and long-term financing. Washington Gas utilizes derivative instruments from time to time in order to minimize its exposure to the risk of interest-rate volatility. Refer to the section entitled " *Long-Term Cash Requirements and Related Financing"* for further discussion of our interest-rate risk management activity.

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WASHINGTON GAS LIGHT COMPANY

This section of Management's Discussion focuses on Washington Gas for the reported periods. In many cases, explanations and disclosures for both WGL Holdings and Washington Gas are substantially the same.

RESULTS OF OPERATIONS — Three Months Ended March 31, 2012 vs. March 31, 2011

The results of operations for the regulated utility segment and Washington Gas are substantially the same; therefore, this section primarily focuses on statistical information and other information that is not discussed in the results of operations for the regulated utility segment. Refer to the section entitled *"Results of Operations—Regulated Utility"* in Management's Discussion for WGL Holdings for a detailed discussion of the results of operations for the regulated utility segment.

Washington Gas' net income applicable to its common stock was $72.1 million and $70.7 million for the three months ended March 31, 2012 and 2011, respectively. Changes in the composition of earnings from the prior period are primarily due to: *(i)* higher revenues due to the implementation of new rates in Maryland and Virginia; *(ii)* an increase in unrealized margins associated with our asset optimization program; *(iii)* lower operation and maintenance expenses, including a benefit from our weather protection and *(iv)* an increase in revenues related to growth of more than 7,900 average active customer meters. Partially offsetting these increases were: *(i)* higher income taxes due to an increase in the effective tax rate including a regulatory write off of a regulatory asset originally recognized in 2010 related to the tax effect of Med D; *(ii)* a reduction in revenue attributed to warmer weather, excluding the benefit of our weather protection; *(iii)* lower realized margins, net of margin sharing, associated with our asset optimization program and *(iv)* an increase in depreciation expense due to the growth in, and changes in the asset mix of, our investment in utility plant.

Key gas delivery, weather and meter statistics are shown in the table below for the three months ended March 31, 2012 and 2011.

Gas Deliveries, Weather and Meter Statistics

	Three Months Ended March 31,		Increase/
	2012	2011	(Decrease)
Gas Sales and Deliveries *(millions of therms)*			
Firm			
Gas sold and delivered	**323.8**	418.2	(94.4)
Gas delivered for others	**172.2**	212.5	(40.3)
Total firm	**496.0**	630.7	(134.7)
Interruptible			
Gas sold and delivered	**0.8**	0.8	-
Gas delivered for others	**78.4**	93.5	(15.1)
Total interruptible	**79.2**	94.3	(15.1)
Electric generation—delivered for others	**35.2**	7.1	28.1
Total deliveries	**610.4**	732.1	(121.7)
Degree Days			
Actual	**1,613**	2,207	(594)
Normal	**2,112**	2,109	3
Percent colder (warmer) than normal	**(23.6)%**	4.6 %	n/a
Average active customer meters	**1,096,571**	1,088,647	7,924
New customer meters added	**2,346**	2,035	311

Gas Service to Firm Customers. The volume of gas delivered to firm customers is highly sensitive to weather variability as a large portion of the natural gas delivered by Washington Gas is used for space heating. Washington Gas' rates are based on an assumption of normal weather. The tariffs in the Maryland and Virginia jurisdictions include provisions that consider the effects of the RNA, WNA and CRA mechanisms, respectively, which are designed to, among other things, eliminate the effect on net revenues of variations in weather from normal levels (refer to the section entitled *"Weather Risk"* for a further discussion of these mechanisms and other weather-related instruments included in our weather protection strategy).

During the quarter ended March 31, 2012 total gas deliveries to firm customers were 496.0 million therms, a decrease of 134.7 million therms from 630.7 million therms delivered in the same quarter of the prior fiscal year. This comparison in natural gas deliveries to firm customers primarily reflects warmer weather in the current quarter than in the same quarter of the prior year, partially offset by an increase in average active customer meters of 7,924.

Weather, when measured by HDDs was 23.6% warmer than normal for the second quarter of fiscal year 2012, compared to 4.6% colder than normal for the same quarter of fiscal year 2011. Due to the extremely warm weather, our weather protection instruments were not sufficient to offset approximately $3.1 million if the reduction in revenue for the three months ended March 31, 2012. There were no material effects on net income attributed to colder or warmer weather for the three months ended March 31, 2011.

Gas Service to Interruptible Customers. Washington Gas must curtail or interrupt service to this class of customer when the demand by firm customers exceeds specified levels. Therm deliveries to interruptible customers decreased by 15.1 million therms in the second quarter of fiscal year 2012 compared to the same quarter of the prior fiscal year, reflecting decreased demand due to warmer weather.

In the District of Columbia, the effect on net income of any changes in delivered volumes and prices to interruptible customers is limited by margin-sharing arrangements that are included in Washington Gas' rate designs in the District of Columbia. In the District of Columbia, Washington Gas shares a majority of the margins earned on interruptible gas sales and deliveries with firm customers. A portion of the fixed costs for servicing interruptible customers is collected through the firm customers' rate design. Rates for interruptible customers in Maryland and Virginia are based on a traditional cost of service approach. In Virginia, Washington Gas retains all revenues above a pre-approved margin threshold level. In Maryland, Washington Gas retains a defined amount of revenues based on a set threshold.

Gas Service for Electric Generation. Washington Gas delivers natural gas for use at two electric generation facilities in Maryland that are each owned by companies independent of WGL Holdings. During the three months ended March 31, 2011, deliveries to these customers increased by 28.1 million therms when compared to the same quarter of the prior year. Washington Gas shares with firm customers a significant majority of the margins earned from natural gas deliveries to these customers. Therefore, changes in the volume of interruptible gas deliveries to these customers do not materially affect either net revenues or net income.

RESULTS OF OPERATIONS — Six Months Ended March 31, 2012 vs. March 31, 2011

Washington Gas' net income applicable to its common stock was $116.3 million and $111.1 million for the six months ended March 31, 2012 and 2011, respectively. Changes in the composition of earnings from the prior period are primarily due to: *(i)* higher revenues due to the implementation of new rates in Maryland and Virginia; *(ii)* an increase in unrealized margins associated with our asset optimization program; *(iii)* lower operation and maintenance expenses and *(iv)* an increase in revenues related to growth of more than 8,700 average active customer meters. Partially offsetting these increases were: *(i)* higher income taxes due to an increase in the effective tax rate including a regulatory write off of a regulatory asset originally recognized in 2010 related to the tax effect of Med D; *(ii)* a reduction in revenue attributed to warmer weather, excluding the benefit of our weather protection; *(iii)* lower realized margins, net of margin sharing, associated with our asset optimization program and *(iv)* an increase in depreciation expense due to the growth in, and changes in the asset mix of, our investment in utility plant.

Key gas delivery, weather and meter statistics are shown in the table below for the six months ended March 31, 2012 and 2011.

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Gas Deliveries, Weather and Meter Statistics

	Six Months Ended March 31,		Increase/
	2012	2011	(Decrease)
Gas Sales and Deliveries *(millions of therms)*			
Firm			
Gas sold and delivered	**556.5**	719.4	(162.9)
Gas delivered for others	**312.8**	379.3	(66.5)
Total firm	**869.3**	1,098.7	(229.4)
Interruptible			
Gas sold and delivered	**1.6**	1.6	—
Gas delivered for others	**150.3**	179.8	(29.5)
Total interruptible	**151.9**	181.4	(29.5)
Electric generation—delivered for others	**43.0**	23.4	19.6
Total deliveries	**1,064.2**	1,303.5	(239.3)
Degree Days			
Actual	**2,807**	3,712	(905)
Normal	**3,462**	3,455	7
Percent colder (warmer) than normal	**(18.9)%**	7.4 %	n/a
Average active customer meters	**1,092,337**	1,083,555	8,782
New customer meters added	**5,802**	4,862	940

Gas Service to Firm Customers. During the six months ended March 31, 2012 total gas deliveries to firm customers were 869.3 million therms, a decrease of 229.4 million therms from 1,098.7 million therms delivered in the same period of the prior fiscal year. This comparison in natural gas deliveries to firm customers primarily reflects warmer weather in the current six months than in the same period of the prior year, partially offset by an increase in average active customer meters of 8,782.

Weather, when measured by HDDs was 18.9% warmer than normal for the six months ended March 31, 2012, compared to 7.4% colder than normal for the same period of fiscal year 2011. Including the effects of our weather protection strategy, there was a $3.1 million unfavorable impact to net income attributed to warmer weather for the three months ended March 31, 2012 and no material effect on net income attributed to colder or warmer weather for the three months ended March 31, 2011.

Gas Service to Interruptible Customers. Therm deliveries to interruptible customers decreased by 29.5 million therms during the six months ended March 31, 2012 compared to the same period of the prior fiscal year, reflecting decreased demand due to warmer weather.

Gas Service for Electric Generation. Washington Gas delivers natural gas for use at two electric generation facilities in Maryland that are each owned by companies independent of WGL Holdings. During the six months ended March 31, 2012, deliveries to these customers increased by 19.6 million therms when compared to the same quarter of the prior year. Washington Gas shares with firm customers a significant majority of the margins earned from natural gas deliveries to these customers. Therefore, changes in the volume of interruptible gas deliveries to these customers do not materially affect either net revenues or net income.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and capital resources for Washington Gas are substantially the same as the liquidity and capital resources discussion included in the Management's Discussion of WGL Holdings (except for certain items and transactions that pertain to WGL Holdings and its unregulated subsidiaries). Those explanations are incorporated by reference into this discussion.

RATES AND REGULATORY MATTERS

Washington Gas determines its request to modify existing rates based on the level of net investment in plant and equipment, operating expenses and the need to earn a just and reasonable return on invested capital. The following is an update of significant current regulatory matters in each of Washington Gas' jurisdictions. For a more detailed discussion of the matters below, refer to our combined Annual Report on Form 10-K for WGL Holdings and Washington Gas for the fiscal year ended September 30, 2011.

District of Columbia Jurisdiction

Investigation of Depreciation Practices. On September 9, 2011, the PSC of DC docketed a proceeding to review the proper and adequate rates of depreciation of the several classes of Washington Gas' property. In accordance with the procedural schedule, interested parties' comments were filed by October 24, 2011. Washington Gas' reply comments were filed on November 14, 2011, wherein Washington Gas requested that the PSC of DC consider depreciation issues in the context of the newly-initiated rate case, referenced below. On April 26, 2012, the PSC of DC granted Washington Gas' request to consolidate its investigation of depreciation issues into its base rate proceeding and closed the proceeding.

District of Columbia Base Rate Case. On November 2, 2011, the PSC of DC docketed a proceeding to investigate the reasonableness of Washington Gas' base rates and charges and required Washington Gas to file a base rate case no later than 90 days from the date of the order. On February 29, 2012, Washington Gas filed a request with the PSC of DC for a $29.0 million annual increase in revenues. The $29.0 million revenue increase requested in this application included a proposed overall rate of return 8.91% and a return on common equity of 10.90%. Washington Gas is also proposing to expand the existing program to replace or encapsulate certain vintage mechanical couplings, which was previously approved by the PSC of DC, to include the accelerated replacement of pipe in its system that is nearing the end of its useful life. Washington Gas plans to invest approximately $119.0 million to replace aging distribution pipe in the District of Columbia over the next five years and included, in this proposal, a request for approval of these expenditures over the next five years. Washington Gas also provided a proposed procedural schedule and requested that the PSC of DC establish a pre-hearing conference. On April 26, 2012, the PSC of DC adopted a procedural schedule and designated issues for the proceeding. Intervenor testimony is due on July 17, 2012, rebuttal testimony is due August 31, 2012, and evidentiary hearings are scheduled in October 2012.

Maryland Jurisdiction

Order on and Reviews of Purchased Gas Charges. Each year, the PSC of MD reviews the annual gas costs collected from customers in Maryland to determine if Washington Gas' purchased gas costs are reasonable.

On September 9, 2011, the PSC of MD issued an order approving purchased gas charges of Washington Gas for the twelve-month period ending August 2009, except for an undetermined amount related to excess gas deliveries by CSPs which were cashed-out by Washington Gas. The PSC of MD found that the cash-out of excess deliveries was in violation of Washington Gas' tariff and that Washington Gas should not have cashed-out the excess deliveries by CSPs, but rather should have eliminated the imbalances through volumetric adjustments in the future and designated that the hearing examiner in a separate proceeding determine whether civil penalties should be levied against Washington Gas. In accordance with generally accepted accounting principles, Washington Gas recorded a $5.3 million estimated regulatory liability associated with this decision during the fourth quarter of fiscal year 2011. On October 11, 2011, Washington Gas filed an application for rehearing of the order with respect to the decision that a violation of the tariff occurred and that civil penalties might be levied. Washington Gas requested that the PSC of MD find that Washington Gas is authorized to cash-out CSP account imbalances under its tariff and therefore is not subject to civil penalties. On January 3, 2012, the PSC of MD issued an order denying Washington Gas' request for rehearing. Pending the ultimate decision of the PSC of MD, further action may be taken with respect to recovery from the CSPs.

Investigation of Asset Management and Gas Purchase Practices. In 2008, the Office of Staff Counsel of the PSC of MD submitted a petition to the PSC of MD to establish an investigation into Washington Gas' asset management program and cost recovery of its gas purchases.

In November 2009, the Chief Hearing Examiner of the PSC of MD issued a POHE, which approved Washington Gas' proposal for the sharing of margins from asset optimization between Washington Gas and customers and its current methodology for pricing storage injections.

Subsequently, both the MD Staff and the OPC filed notices of appeal of the POHE followed by a memorandum on appeal in support of their positions. In January 2010, Washington Gas filed a reply memorandum in response to the Staff of the PSC of MD and the MD OPC's memoranda on appeal. A decision by the PSC of MD is pending.

Maryland Base Rate Case. On November 14, 2011, the PSC of MD issued an order authorizing: *(i)* an annual revenue increase of $8.4 million compared to Washington Gas' revised request of $27.8 million; *(ii)* a rate of return on common equity of 9.60% and an overall rate of return of 8.09%; and *(iii)* an end of test period equity ratio of 57.88%. The order also authorized Washington Gas to implement the initial 5-year phase of the accelerated pipe replacement plan, but denied the proposed cost recovery mechanism; and disallowed the amortization of costs to achieve under Washington Gas' BPO agreement.

On December 14, 2011, Washington Gas filed a petition for rehearing and clarification of the PSC of MD's November 14, 2011 order to *(i)* correct the methodology used to calculate the adjustment related to interest synchronization, which would increase the revenue requirement determined by the PSC of MD in its order by $0.7 million, *(ii)* correct the omission of an adjustment related to "Other Tax Adjustments," which would increase the revenue requirement by an additional $2.4 million, and *(iii)* reverse the decision to disallow $1.0 million of Washington Gas' test period costs to achieve Washington Gas' BPO agreement. Washington Gas also requested clarification related to implementation of the accelerated pipe replacement plan and what annual reporting requirements may apply.

On March 29, 2012, the PSC of MD issued an order in response to the petition for rehearing and clarification filed by Washington Gas. The PSC of MD *(i)* granted an additional revenue increase of $0.7 million related to interest synchronization, increasing the overall revenue increase granted to Washington Gas in the case to $9.1 million; *(ii)* denied Washington Gas' request for an adjustment related to other tax adjustments, which would have increased the revenue requirement by an additional $2.4 million; *(iii)* denied recovery of the costs to initiate the outsourcing agreement with Accenture LLC in 2007; and *(iv)* directed Washington Gas to provide written notice when it implements the accelerated pipeline replacement project and adopted the reporting structure suggested by a MD Staff witness as guidance for reporting Washington Gas' progress. As a result of this order, Washington Gas recorded a $2.8 million charge to income tax expense to write-off a regulatory asset that had been established in 2010 for the change in the tax treatment of Medicare Part D, the amortization of which comprised the majority of the other tax adjustments that were disallowed by the Commission.

On April 30, 2012, Washington Gas filed a petition for rehearing with the PSC of MD which requested the Commission reverse its decisions in the March 29, 2012 order denying Washington Gas' request for an adjustment related to other tax adjustments and the costs to initiate the outsourcing agreement with Accenture, LLC. Washington Gas also filed a petition for judicial review of the PSC of MD's March 29, 2012 order with the Circuit Court for Baltimore City to preserve its right to appeal in this case. Washington Gas has requested the Circuit Court to hold further proceedings on the appeal in abeyance pending the PSC of MD's action on the petition for rehearing.

Virginia Jurisdiction

Conservation and Ratemaking Efficiency Plan. On July 22, 2010, Washington Gas filed an amendment to the CARE Plan to include small commercial and industrial customers in Virginia. The application included a portfolio of conservation and energy efficiency programs, an associated cost recovery provision and a decoupling mechanism that will adjust weather normalized non-gas distribution revenues for the impact of conservation or energy efficiency efforts. On November 18, 2010, the SCC of VA issued an order that denied Washington Gas' application. The SCC of VA found that Washington Gas' current tariff and its underlying class cost of service and revenue apportionment studies do not segregate small versus large customers and that only small customers qualify under the CARE law. The SCC of VA stated that Washington Gas could amend the underlying tariff and studies in connection with its required 2011 base rate case filing. Such a tariff amendment was proposed in the new base rate case filing made with the SCC of VA, which is pending a commission decision.

Virginia Base Rate Case. On January 31, 2011, Washington Gas filed a request with the SCC of VA for a $29.6 million annual increase in revenues. The filing was made pursuant to the settlement agreement reached by the parties and approved by the SCC of VA in Washington Gas' last base rate case, which resulted in a PBR plan. On May 12, 2011, Washington Gas revised its requested revenue increase from $29.6 million to $28.5 million as a result of new proposed depreciation rates. Interim rates went into effect on October 1, 2011 with the requested increase subject to refund pending a final commission decision.

On November 30, 2011, Washington Gas filed a stipulation to reflect settlement terms to which Washington Gas, the Staff, and other stipulating parties to the settlement agreed. The AOBA did not support this stipulation. In the stipulation, the settling parties agreed to a $20.0 million rate increase, a 9.75% return on equity, an 8.261% overall rate of return, and a provision for sharing margins from asset optimization activities between Washington Gas and customers which includes a $3.2 million annual guarantee. Evidentiary hearings were held on December 5 and 6, 2011. Post-hearing briefs were filed on January 26, 2012. On March 15, 2012, the Senior Hearing Examiner issued a report of findings and recommended that the SCC of VA adopt the stipulation. On April 5, 2012, Washington Gas, the Staff of the SCC of VA, the Office of the Attorney General and Fairfax County all filed comments in support of the recommended decision of the Hearing Examiner while the AOBA filed comments in opposition. On April 18, 2012, Washington Gas filed a petition for leave to file reply and reply to AOBA's comments on the Hearing Examiner's report. A commission decision is pending.

Affiliate Transactions. On June 16, 2011, Washington Gas submitted an application to the SCC of VA requesting approval of three affiliate transactions with CEV: *(i)* the transfer to CEV of the remainder of the term of two agreements for natural gas storage service at the WSS and ESS storage fields; *(ii)* the sale to CEV of any storage gas balances associated with the WSS and ESS agreements; and *(iii)* the assignment to CEV of Washington Gas' rights to buy base gas in the WSS storage field. Washington Gas proposed to make these affiliate transactions by September 30, 2011, coincident with the expiration of its PBR plan approved by the SCC of VA in a separate proceeding. On September 14, 2011, the SCC of VA issued an order denying Washington Gas' application to transfer Washington Gas' contracts for certain storage capacity resources to its affiliate, CEV. On October 4, 2011, Washington Gas filed a petition for reconsideration on this proceeding. On October 5, 2011, the SCC of VA granted Washington Gas' request that the matter be reconsidered, but has not made a final ruling on Washington Gas' petition for reconsideration. On December 6, 2011, the VA Staff submitted a supplement to action brief seeking to provide evidence to the commission that ratepayers have been funding the WSS and ESS assets during the PBR period based on the netting of costs associated with those assets when calculating net revenues.

Washington Gas submitted comments rejecting the Staff's position and showing that the ratepayers had not funded these assets. These comments were appended to the VA Staff's brief on December 9, 2011. A commission decision is pending.

OTHER MATTERS

New Labor Contract. Washington Gas has entered into a new three-year labor contract with the Teamsters Local Union No. 96 (Local 96), a local union affiliated with the International Brotherhood of Teamsters. The contract covers approximately 540 employees. The Teamsters ratified the contract on January 31, 2012 and is effective through May 31, 2015. The contract includes, among other things: *(i)* annual wage increases ranging from 2.25% to 3.25%; *(ii)* employment protection for each Local 96 employee employed at the date of ratification; *(iii)* discontinuance of the leave of absence pending retirement benefit as of June 1, 2012 and *(iv)* an increase in employee's contribution to its medical benefits consistent with medical benefit plans for all other company employees.

WGL Holdings, Inc.
Washington Gas Light Company
Part I—Financial Information

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following issues related to our market risks are included under Item 2, *Management's Discussion and Analysis of Financial Condition and Results of Operations* , and are incorporated by reference into this discussion.

- Price Risk Related to the Regulated Utility Segment
- Price Risk Related to the Non-Utility Segments
- Weather Risk
- Interest-Rate Risk

ITEM 4. CONTROLS AND PROCEDURES – WGL Holdings

Senior management, including the Chairman and Chief Executive Officer, and the Vice President and Chief Financial Officer, evaluated the effectiveness of WGL Holdings' disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of March 31, 2012. Based on this evaluation process, the Chairman and Chief Executive Officer, and the Vice President and Chief Financial Officer have concluded that disclosure controls and procedures of WGL Holdings are effective. There have been no changes in the internal control over financial reporting of WGL Holdings during the quarter ended March 31, 2012 that have materially affected, or are reasonably likely to materially affect, the internal control over financial reporting of WGL Holdings.

ITEM 4. CONTROLS AND PROCEDURES—Washington Gas

Senior management, including the Chairman and Chief Executive Officer, and the Vice President and Chief Financial Officer, evaluated the effectiveness of the disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) of Washington Gas as of March 31, 2012. Based on this evaluation process, the Chairman and Chief Executive Officer, and the Vice President and Chief Financial Officer have concluded that the disclosure controls and procedures of Washington Gas are effective. There have been no changes in the internal control over financial reporting of Washington Gas during the quarter ended March 31, 2012 that have materially affected, or are reasonably likely to materially affect, the internal control over financial reporting of Washington Gas.

WGL Holdings, Inc.
Washington Gas Light Company
Part II—Other Information

ITEM 1. LEGAL PROCEEDINGS

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. For information regarding pending federal and state regulatory matters, see Note 13 — *Commitments and Contingencies* , contained in Part I under the Notes to Consolidated Financial Statements. Also, see Part II, Item 1 of our Form 10-Q for the quarter ended December 31, 2011 for the description of a material ongoing legal proceeding. There were no material developments in this matter during the quarter ended March 31, 2012.

ITEM 6. EXHIBITS

Exhibits:

Schedule/ Exhibit	Description
(a)(3)	Exhibits
	Exhibits Filed Herewith:
10.1	Credit Agreement dated as of April 3, 2012 among WGL Holdings, Inc., the Lenders Parties Hereto, Wells Fargo Bank, National Association, as administrative agent; The Bank of Tokyo-Mitsubishi UFJ, Ltd. as syndication agent; Branch Banking and Trust Company and TD Bank, N.A., as documentation agents; and Wells Fargo Securities, LLC, The Bank of Tokyo-Mitsubishi UFJ, Ltd., BB&T Capital Markets and TD Bank, N.A. as joint lead arrangers and joint book runners.
10.2	Credit Agreement dated as of April 3, 2012 among Washington Gas Light Company, the Lenders Parties Hereto, Wells Fargo Bank, National Association, as administrative agent; The Bank of Tokyo-Mitsubishi UFJ, Ltd. as syndication agent; Branch Banking and Trust Company and TD Bank, N.A., as documentation agents; and Wells Fargo Securities, LLC, The Bank of Tokyo-Mitsubishi UFJ, Ltd., BB&T Capital Markets and TD Bank, N.A. as joint lead arrangers and joint book runners.
31.1	Certification of Terry D. McCallister, the Chairman and Chief Executive Officer of WGL Holdings, Inc., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Vincent L. Ammann, Jr., the Vice President and Chief Financial Officer of WGL Holdings, Inc., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.3	Certification of Terry D. McCallister, the Chairman and Chief Executive Officer of Washington Gas Light Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Certification of Vincent L. Ammann, Jr., the Vice President and Chief Financial Officer of Washington Gas Light Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification of Terry D. McCallister, the Chairman and Chief Executive Officer, and Vincent L. Ammann, Jr., the Vice President and Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	Exhibits Submitted Herewith:
101.INS	XBRL Instance Document: *
101.SCH	XBRL Schema Document: *
101.CAL	XBRL Calculation Linkbase Document: *
101.LAB	XBRL Labels Linkbase Document: *
101.PRE	XBRL Presentation Linkbase Document: *
101.DEF	XBRL Definition Linkbase Document. *
3	*Articles of Incorporation & Bylaws:*
	Washington Gas Light Company Charter, filed on Form S-3 dated July 21, 1995.
	WGL Holdings, Inc. Charter, filed on Form S-4 dated February 2, 2000.
	Bylaws of WGL Holdings, Inc. as amended on March 5, 2009, filed as Exhibit 3(ii) to Form 8-K on March 6, 2009.
	Bylaws of Washington Gas Light Company as amended on December 16, 2011, filed as Exhibit 3(ii) to Form 8-K on December 21, 2011.

* *Attached as Exhibit 101 to this Quarterly Report are the financial statements and related footnotes of WGL Holdings, Inc. and Washington Gas Light Company formatted in extensible business reporting language (XBRL): Consolidated Balance Sheets (Unaudited); Consolidated Statements of Income (Unaudited); Consolidated Statements of Cash Flows (Unaudited); Balance Sheets (Unaudited); Statements of Income (Unaudited); Statements of Cash Flows (Unaudited) and Related Footnotes (Unaudited). Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed furnished, not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability. We also*

make available on our web site the Interactive Data Files submitted as Exhibit 101 to this Quarterly Report.

WGL Holdings, Inc.
Washington Gas Light Company

Signature

Pursuant to the requirements the Securities Exchange Act of 1934, the Registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized.

WGL HOLDINGS, INC.
and
WASHINGTON GAS LIGHT COMPANY
(Co-registrants)

Date: May 3, 2012

/s/ William R. Ford

William R. Ford
Controller (Principal Accounting Officer

Exhibit 10.1

Execution Version

Published Deal CUSIP: 9292EDAC4
Published Revolving Facility CUSIP: 9292EDAD2

CREDIT AGREEMENT

DATED AS OF APRIL 3, 2012

AMONG

WGL HOLDINGS, INC.,

THE LENDERS PARTIES HERETO,

**WELLS FARGO BANK, NATIONAL ASSOCIATION,
AS ADMINISTRATIVE AGENT,**

**THE BANK OF TOKYO-MITSUBISHI UFJ, LTD.,
AS SYNDICATION AGENT,**

**BRANCH BANKING AND TRUST COMPANY AND
TD BANK, N.A.
AS DOCUMENTATION AGENTS,**

AND

**WELLS FARGO SECURITIES, LLC,
THE BANK OF TOKYO-MITSUBISHI UFJ, LTD.,
BB&T CAPITAL MARKETS AND
TD BANK, N.A.
AS JOINT LEAD ARRANGERS AND JOINT BOOK RUNNERS**

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CREDIT AGREEMENT, dated as of April 3, 2012 (the "Agreement"), among WGL HOLDINGS, INC., as Borrower, the financial institutions from time to time parties hereto, as LENDERS, WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent, THE BANK OF TOKYO-MITSUBISHI UFJ, LTD., as Syndication Agent, and BRANCH BANKING AND TRUST COMPANY and THE TORONTO-DOMINION BANK, as Documentation Agents.

RECITALS

WHEREAS, the Borrower has requested that the Lenders provide a revolving credit facility, and the Lenders are willing to do so on the terms and conditions set forth herein.

NOW, THEREFORE, the parties hereto agree as follows:

ARTICLE I

INTERPRETATION

1.1 Definitions. As used in this Agreement:

"Acquisition" means any transaction, or any series of related transactions, consummated on or after the Agreement Date, by which the Borrower or any of its Subsidiaries (i) acquires any going business or all or substantially all of the assets of any firm, corporation or limited liability company, or division thereof, whether through purchase of assets, merger or otherwise, or (ii) directly or indirectly acquires (in one transaction or as the most recent transaction in a series of transactions) at least a majority (in number of votes) of the securities of a corporation which have ordinary voting power for the election of directors (other than securities having such power only by reason of the happening of a contingency) or a majority (by percentage or voting power) of the outstanding ownership interests of a partnership or limited liability company.

"Active Arrangers Fee Letter" means the letter to the Borrower from Wells Fargo Securities and BTMU, dated as of February 15, 2012.

"Additional Commitment Lender" is defined in Section 2.5.2.

"Administrative Agent" means Wells Fargo Bank, National Association, in its capacity as administrative agent for the Lenders pursuant to Article X, and not in its individual capacity as a Lender or any successor Administrative Agent appointed pursuant to Article X.

"Administrative Questionnaire" means an Administrative Questionnaire in a form supplied by the Administrative Agent.

"Administrative Fee Letter" means the letter to the Borrower from Wells Fargo dated as of February 15, 2012.

"Affiliate" of any Person means any other Person directly or indirectly controlling, controlled by or under common control with such Person. A Person shall be deemed to control another Person if the controlling Person owns 10% or more of any class of voting securities (or other ownership interests) of the controlled Person or possesses, directly or indirectly, the power to direct or cause the direction of the management or policies of the controlled Person, whether through ownership of stock, by contract or otherwise.

" Aggregate Commitments " means the aggregate of the Commitments of all the Lenders, in the initial aggregate amount of $450,000,000, as increased or decreased from time to time pursuant to the terms hereof.

" Agreement " means this Agreement, including all schedules, annexes and exhibits hereto.

" Agreement Date " means the first date all the conditions precedent set forth in Sections 4.1 and 4.2 shall have been satisfied or waived in accordance with the terms of this Agreement, which is **April 3, 2012** .

" Alternate Base Rate " means, for any day, a fluctuating rate per annum equal to the highest of (i) the Prime Rate for such day, (ii) the Federal Funds Effective Rate for such day plus 0.50%, and (iii) the LIBOR Rate plus 1.00%.

" Applicable Law " means, anything in Section 15.1 to the contrary notwithstanding, (i) all applicable common law and principles of equity and (ii) all applicable provisions of all (A) treaties, constitutions, statutes, rules, regulations, guidelines and orders of governmental bodies, including the interpretation or administration thereof by any Governmental Authority charged with the enforcement, interpretation or administration thereof, (B) Governmental Approvals and (C) orders, decisions, judgments and decrees.

" Applicable Margin " means, with respect to Loans of any Type at any time, the percentage rate per annum which is applicable at such time with respect to Loans of such Type as set forth in the Pricing Schedule.

" Applicable Percentage " means, with respect to any Lender at any time, the percentage of the Aggregate Commitments represented by such Lender's Commitment at such time, subject to adjustment as provided in Section 2.22 . If the commitment of each Lender to make Loans and the obligation of the Issuing Banks to issue Letters of Credit have been terminated pursuant to Section 8.1 , or if the Aggregate Commitments have expired, then the Applicable Percentage of each Lender shall be determined based on the Applicable Percentage of such Lender most recently in effect, giving effect to any subsequent assignments.

" Arrangers " means Wells Fargo Securities, BTMU, BB&TCM and TD, each in its capacity as a joint lead arranger and bookrunner.

" Authorized Officer " means any of the Vice President and Chief Financial Officer, Vice President and General Counsel, or the Treasurer of the Borrower, acting singly.

" Bankruptcy Code " means the United States Bankruptcy Code (11 U.S.C. §101 et seq.).

" Base Rate Loan " means a Loan which, except as otherwise provided in Section 2.8 , bears interest at the Alternate Base Rate plus the Applicable Margin.

" BB&T " means Branch Banking and Trust Company, and its successors.

" BB&TCM " means BB&T Capital Markets, and its successors.

" Borrower " means WGL Holdings, Inc., a Virginia corporation.

" Borrowing Date " means a date on which a Loan is made.

" Borrowing Notice " is defined in Section 2.2.2.

" BTMU " means The Bank of Tokyo-Mitsubishi UFJ, Ltd., and its successors.

" Business Day " means (i) any day other than a Saturday or Sunday, a legal holiday, or a day on which commercial banks in Charlotte, North Carolina or New York, New York are authorized or required by law to be closed and (ii) in respect of any LIBOR determination, any such day that is also a day on which trading in Dollar deposits is conducted by banks in London, England in the London interbank eurodollar market.

" Capitalized Lease " of a Person means any lease of Property by such Person as lessee which would be capitalized on a balance sheet of such Person prepared in accordance with GAAP.

" Capitalized Lease Obligations " of a Person means the amount of the obligations of such Person under Capitalized Leases which would be shown as a liability on a balance sheet of such Person prepared in accordance with GAAP.

" Cash Collateral Account " has the meaning given to such term in Section 3.8.

" Cash Collateralize " means to pledge and deposit with or deliver to the Administrative Agent, for the benefit of the Administrative Agent, the Issuing Banks and the Lenders, as collateral for the Letter of Credit Exposure or obligations of Lenders to fund participations in respect of Letter of Credit Exposure, cash or deposit account balances or, if the Administrative Agent and the Issuing Banks shall agree in their sole discretion, other credit support, in each case pursuant to documentation in form and substance satisfactory to the Administrative Agent and the Issuing Banks. " Cash Collateral " shall have a meaning correlative to the foregoing and shall include the proceeds of such cash collateral and other credit support.

" Cash Equivalents " means (i) short-term obligations of, or fully guaranteed by, the United States of America, (ii) commercial paper rated A-1 or better by S&P or Fitch or P-1 or better by Moody's, (iii) demand deposit accounts maintained in the ordinary course of business, and (iv) certificates of deposit issued by, and time deposits with, commercial banks (whether domestic or foreign) having capital and surplus in excess of $100,000,000; provided in each case that the same provides for payment of both principal and interest (and not principal alone or interest alone) and is not subject to any contingency regarding the payment of principal or interest.

" CERCLA " means the Comprehensive Environmental Response, Compensation and Liability Act of 1980.

“ CERCLIS ” means the Comprehensive Environmental Response, Compensation, and Liability Information System List.

“ Change in Law ” means the occurrence, after the date of this Agreement, of any of the following: (i) the adoption or taking effect of any law, rule, regulation or treaty, (ii) any change in any law, rule, regulation or treaty or in the administration, interpretation, implementation or application thereof by any Governmental Authority or (iii) the making or issuance of any request, rule, guideline or directive (whether or not having the force of law) by any Governmental Authority; provided that notwithstanding anything herein to the contrary, (x) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives thereunder or issued in connection therewith and (y) all requests, rules, guidelines or directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or the United States or foreign regulatory authorities, in each case pursuant to Basel III, shall in each case be deemed to be a “Change in Law”, regardless of the date enacted, adopted or issued.

“ Change in Control ” means (i) an event or series of events by which any “person” or “group” (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any employee benefit plan of such person or its Subsidiaries, and any person or entity acting in its capacity as trustee, agent or other fiduciary or administrator of any such plan) becomes the “beneficial owner” (as defined in Rules 13d-3 and 13d-5 under the Exchange Act, except that a “person” or “group” shall be deemed to have “beneficial ownership” of all capital stock that such “person” or “group” has the right to acquire, whether such right is exercisable immediately or only after the passage of time (such right, an “option right”)), directly or indirectly, of more than thirty percent (30%) of the capital stock of the Borrower entitled to vote in the election of members of the board of directors (or equivalent governing body) of the Borrower or (ii) a majority of the members of the board of directors (or other equivalent governing body) of the Borrower shall not constitute Continuing Directors.

“ Code ” means the Internal Revenue Code of 1986.

“ Commitment ” means, for each Lender, the obligation of such Lender to make Loans not exceeding the amount set forth opposite such Lenders name on Schedule 1.1-B , as it may be modified as a result of any assignment that has become effective pursuant to Section 12.3.2 or as otherwise decreased or increased from time to time pursuant to the terms hereof.

“ Commitment Increase ” is defined in Section 2.5.2 .

“ Commitment Increase Supplement ” is defined in Section 2.5.2 .

“ Compliance Certificate ” is defined in Section 4.2 .

“ Connection Income Taxes ” means Other Connection Taxes that are imposed on or measured by net income (however denominated) or that are franchise Taxes or branch profits Taxes.

“ Consolidated Financial Indebtedness ” means at any time the Financial Indebtedness of the Borrower and its Subsidiaries calculated on a consolidated basis as of such time.

" Consolidated Net Worth " means at any time the sum of common shareholders' equity of the Borrower and preferred stock of the Utility, as reported on the consolidated balance sheet of the Borrower prepared as of such time.

" Consolidated Total Capitalization " means at any time the sum of Consolidated Financial Indebtedness and Consolidated Net Worth, each calculated at such time.

" Contingent Obligation " of a Person means any agreement, Contract, undertaking or arrangement by which such Person assumes, guarantees, endorses, contingently agrees to purchase or provide funds for the payment of, or otherwise becomes or is contingently liable upon, the obligation or liability of any other Person, or agrees to maintain the net worth or working capital or other financial condition of any other Person, or otherwise assures any creditor of such other Person against loss, including, without limitation, any comfort letter, operating agreement, take or pay contract or the obligations of any such Person as general partner of a partnership with respect to the liabilities of the partnership.

" Continuing Directors " shall mean the directors of the Borrower on the Agreement Date and each other director of the Borrower, if, in each case, such other director's nomination for election to the board of directors (or equivalent governing body) of the Borrower is recommended by at least 51% of the then Continuing Directors.

" Contract " means (i) any agreement, including an indenture, lease or license, (ii) any deed or other instrument of conveyance, (iii) any certificate of incorporation or charter and (iv) any by-law.

" Controlled Group " means all members of a controlled group of corporations and all members of a group of trades or businesses (whether or not incorporated) under common control, which together with the Borrower are treated as a single employer under Section 414(b) or 414(c) of the Code or Section 4001 of ERISA.

" Conversion/Continuation Notice " is defined in Section 2.2.7 .

" Credit Exposure " means, with respect to any Lender at any time, the sum of (i) the aggregate principal amount of all Loans made by such Lender that are outstanding at such time, (ii) such Lender's Swingline Exposure at such time and (iii) such Lender's Letter of Credit Exposure at such time.

" Defaulting Lender " means, subject to Section 2.22.2 any Lender that (i) has failed to (x) fund all or any portion of its Loans within two Business Days of the date such Loans were required to be funded hereunder unless such Lender notifies the Administrative Agent and the Borrower in writing that such failure is the result of such Lender's determination that one or more conditions precedent to funding (each of which conditions precedent, together with any applicable default, shall be specifically identified in such writing) has not been satisfied, or (y) pay to the Administrative Agent, any Issuing Bank, any Swingline Lender or any other Lender any other amount required to be paid by it hereunder (including in respect of its participation in Letters of Credit or Swingline Loans) within two Business Days of the date when due, (ii) has notified the Borrower, the Administrative Agent or any Issuing Bank or Swingline Lender in writing that it does not intend to comply with its funding obligations hereunder, or has made a public statement to that effect (unless such writing or public statement relates to such Lender's obligation to fund a Loan hereunder and states that such position is based on such Lender's determination that a condition precedent to funding (which condition precedent, together with any applicable default, shall be specifically identified in such writing or public statement) cannot be satisfied), (iii) has failed, within three Business Days after written request by the Administrative Agent or the Borrower, to confirm in writing to the Administrative Agent and the Borrower that it will comply with its prospective funding obligations hereunder (provided that such Lender shall cease to be a Defaulting Lender pursuant to this clause (iii) upon receipt of such written confirmation by the Administrative Agent and the Borrower), or (iv) has, or has a direct or indirect parent company that has, (x) become the subject of a proceeding under the Bankruptcy Code or under other applicable bankruptcy, insolvency or similar law now or hereafter in effect, or (y) had appointed for it a receiver, custodian, conservator, trustee, administrator, assignee for the benefit of creditors or similar Person charged with reorganization or liquidation of its business or assets, including the Federal Deposit Insurance Corporation or any other state or federal regulatory authority acting in such a capacity; provided that a Lender shall not be a Defaulting Lender solely by virtue of the ownership or acquisition of any equity interest in that Lender or any direct or indirect parent company thereof by a Governmental Authority so long as such ownership interest does not result in or provide such Lender with immunity from the jurisdiction of courts within the United States or from the enforcement of judgments or writs of attachment on its assets or permit such Lender (or such Governmental Authority) to reject, repudiate, disavow or disaffirm any contracts or agreements made with such Lender. Any determination by the Administrative Agent that a Lender is a Defaulting Lender under any one or more of clauses (i) through (iv) above shall be conclusive and binding absent manifest error, and such Lender shall be deemed to be a Defaulting Lender (subject to Section 2.22.2) upon delivery of written notice of such determination by the Administrative Agent to the Borrower, the Issuing Bank, the Swingline Lender and each Lender.

" Documentation Agent " means each of BB&T and TD, acting in the capacity as documentation agent hereunder.

" Dollars " and the sign " $ " mean lawful money of the United States of America.

" Eligible Assignee " means any Lender, Affiliate of a Lender or other Person that meets the requirements to be an assignee under Section 12.3.1 .

" Employee Benefit Plans " is defined in Section 5.8 .

" Environmental Laws " means any and all federal, state, local and foreign statutes, Applicable Laws, judicial decisions, regulations, ordinances, rules, judgments, orders, decrees, plans, injunctions, permits, concessions, grants, franchises, licenses, agreements and other governmental restrictions relating to (i) the protection of the environment, (ii) the effect of the environment on human health, (iii) emissions, discharges or releases of pollutants, contaminants, hazardous substances or wastes into ambient air, surface water, ground water, land surface or subsurface strata, or (iv) the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of pollutants, contaminants, hazardous substances or wastes or the clean-up or other remediation thereof.

" ERISA " means the Employee Retirement Income Security Act of 1974.

" Event of Default " means an event described in Article VII .

" Exchange Act " means Securities Exchange Act of 1934.

" Excluded Taxes " means any of the following Taxes imposed on or with respect to a Recipient or required to be withheld or deducted from a payment to a Recipient, (i) Taxes imposed on or measured by net income (however denominated), franchise Taxes, and branch profits Taxes, in each case, (x) imposed as a result of such Recipient being organized under the laws of, or having its principal office or, in the case of any Lender, its Lending Installation located in, the jurisdiction imposing such Tax (or any political subdivision thereof) or (y) that are Other Connection Taxes, (ii) in the case of a Lender, U.S. federal withholding Taxes imposed on amounts payable to or for the account of such Lender with respect to an applicable interest in a Loan or Commitment pursuant to a law in effect on the date on which (x) such Lender acquires such interest in the Loan or Commitment (other than pursuant to an assignment request by the Borrower under Section 2.21) or (y) such Lender changes its Lending Installation, except in each case to the extent that, pursuant to Section 2.19 , amounts with respect to such Taxes were payable either to such Lender's assignor immediately before such Lender became a party hereto or to such Lender immediately before it changed its Lending Installation, (iii) Taxes attributable to such Recipient's failure to comply with Section 2.19.7 and (iv) any U.S. federal withholding Taxes imposed under FATCA.

" Existing Credit Agreement " means that certain Amended and Restated Credit Agreement dated as of August 3, 2007, among the Borrower, the several lender parties listed on the signature pages thereof, Wachovia Bank, National Association, as administrative agent, Bank of Tokyo-Mitsubishi UFJ Trust Company, as syndication agent, and SunTrust Bank and Citibank, N.A., as documentation agents.

" Extension Option " means the option of the Borrower under Section 2.6 hereof to extend the Facility Termination Date.

" Facility Fee " is defined in Section 2.4.2 .

" Facility Fee Rate " means, at any time, the percentage rate per annum at which Facility Fees are accruing on the Aggregate Commitments (without regard to usage) at such time as set forth in the Pricing Schedule.

" Facility Termination Date " means September 30, 2012, provided that upon the delivery of certified resolutions of the Board of Directors of the Borrower, reasonably satisfactory to the Administrative Agent, authorizing the Borrower's performance of its obligations under the Loan Documents through the fifth anniversary of the Agreement Date, the fifth anniversary of the Agreement Date (as such date may be extended from time to time pursuant to Section 2.6).

" FATCA " means Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended version that is substantively comparable) and any current or future regulations or official interpretations thereof.

"Federal Funds Effective Rate" means, for any day, an interest rate per annum equal to the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System arranged by Federal funds brokers on such day, as published for such day (or, if such day is not a Business Day, for the immediately preceding Business Day) by the Federal Reserve Bank of New York, or, if such rate is not so published for any day which is a Business Day, the average of the quotations at approximately 10:00 a.m. on such day on such transactions received by the Administrative Agent from three Federal funds brokers of recognized standing selected by the Administrative Agent in its sole discretion.

"Fee Letters" means, collectively, the Active Arrangers Fee Letter, Passive Arrangers Fee Letter and Administrative Fee Letter.

"Financial Indebtedness" of a Person means such Person's (i) obligations for borrowed money which, in accordance with GAAP, would be shown as short-term debt on a consolidated balance sheet of such Person, including obligations under notes, commercial paper, acceptances and other short-term instruments, and (ii) obligations for borrowed money which, in accordance with GAAP, would be shown as long-term debt (including current maturities) on a consolidated balance sheet of such Person.

"Fitch" means Fitch Ratings, Ltd.

"Foreign Lender" means (i) if the Borrower is a U.S. Person, a Lender that is not a U.S. Person, and (ii) if the Borrower is not a U.S. Person, a Lender that is resident or organized under the laws of a jurisdiction other than that in which the Borrower is resident for tax purposes.

"Fronting Exposure" means, at any time there is a Defaulting Lender, (i) with respect to any Issuing Bank, such Defaulting Lender's Letter of Credit Exposure with respect to Letters of Credit issued by such Issuing Bank other than such portion of such Defaulting Lender's Letter of Credit Exposure as to which such Defaulting Lender's participation obligation has been reallocated to other Lenders or Cash Collateralized in accordance with the terms hereof, and (ii) with respect to any Swingline Lender, such Defaulting Lender's Swingline Exposure with respect to outstanding Swingline Loans made by the Swingline Lender other than Swingline Loans as to which such Defaulting Lender's participation obligation has been reallocated to other Lenders in accordance with the terms hereof.

"GAAP" means generally accepted accounting principles in the United States of America, as set forth in the statements, opinions and pronouncements of the Accounting Principles Board, the American Institute of Certified Public Accountants and the Financial Accounting Standards Board, consistently applied and maintained, as in effect from time to time (subject to the provisions of Section 1.2).

"Governmental Approval" means any authority, consent, approval, license (or the like) or exemption (or the like) of any governmental unit.

"Governmental Authority" means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supranational bodies such as the European Union or the European Central Bank).

" Hazardous Material " means: any "hazardous substance", as defined by CERCLA; any petroleum product; or any pollutant or contaminant or hazardous, dangerous or toxic chemical, material or substance within the meaning of any other Environmental Law.

" Hedge Agreement " means any interest or foreign currency rate swap, cap, collar, option, hedge, forward rate or other similar agreement or arrangement designed to protect against fluctuations in interest rates, currency exchange rates or spot prices of new materials.

" Indebtedness " of a Person means such Person's (i) obligations for borrowed money, (ii) obligations representing the deferred purchase price of Property or services (other than accounts payable arising in the ordinary course of such Person's business payable on terms customary in the trade, (iii) obligations, whether or not assumed, secured by Liens on, or payable out of the proceeds or production from, Property now or hereafter owned or acquired by such Person, (iv) obligations which are evidenced by bonds, debentures, notes, acceptances, or other instruments, (v) obligations of such Person to purchase securities or other Property arising out of or in connection with the sale of the same or substantially similar securities or Property, (vi) Capitalized Lease Obligations, (vii) any other obligation for borrowed money or other financial accommodation which in accordance with GAAP would be shown as a liability on the consolidated balance sheet of such Person, (viii) Contingent Obligations in respect of any type of obligation described in any of the other clauses of this definition, (ix) obligations in respect letters of credit (including standby and commercial), bankers' acceptances, bank guaranties, surety bonds and similar instruments, (x) for all purposes other than Section 6.6 , net obligations under any Hedge Agreements, (xi) Operating Lease Obligations, (xii) obligations in respect of Sale and Leaseback Transactions and (xiii) Off-Balance Sheet Liabilities. Permitted Commodity Hedging Obligations shall not constitute Indebtedness for purposes of this Agreement.

" Indemnified Person " means any Person that is, or at any time was, the Administrative Agent, the Syndication Agent, a Documentation Agent, a Lender or an Arranger or an Affiliate, director, officer, employee or agent of any such Person.

" Indemnified Taxes " means (i) Taxes, other than Excluded Taxes, imposed on or with respect to any payment made by or on account of any obligation of the Borrower under any Loan Document and (ii) to the extent not otherwise described in clause (i), Other Taxes.

" Indemnitee " is defined in Section 9.6.2 .

" Interest Period " means, with respect to a LIBOR Rate Loan, the period commencing on the date such LIBOR Rate Loan is disbursed or converted to or continued as a LIBOR Rate Loan and ending on the date one, two, three or six months thereafter, as selected by the Borrower pursuant to this Agreement; provided , that (i) any Interest Period pertaining to a LIBOR Rate Loan that begins on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the calendar month at the end of such Interest Period) shall end on the last Business Day of the calendar month at the end of such Interest Period, (ii) any Interest Period that would otherwise end on a day that is not a Business Day shall be extended to the next succeeding Business Day unless such Business Day falls in another calendar month, in which case such Interest Period shall end on the next preceding Business Day; and (iii) no Interest Period shall extend beyond the Facility Termination Date.

" Issuing Bank " means each of Wells Fargo and BB&T, in their respective capacities as issuers of Letters of Credit under this Agreement.

" LC Fee " is defined in Section 2.4.4 .

" Lenders " means the lending institutions listed on the signature pages of this Agreement, any Additional Commitment Lenders, and their respective successors and assigns.

" Lending Installation " means, with respect to a Lender or the Administrative Agent, the office, branch, subsidiary or affiliate of such Lender or the Administrative Agent designated on its Administrative Questionnaire or otherwise selected by such Lender or the Administrative Agent pursuant to Section 2.1 5.

" Letter of Credit Exposure " means, with respect to any Lender at any time, such Lender's ratable share (based on the proportion that its Commitment bears to the Aggregate Commitments at such time) of the sum of (i) the aggregate Stated Amount of all Letters of Credit outstanding at such time and (ii) the aggregate amount of all Reimbursement Obligations outstanding at such time.

" Letter of Credit Maturity Date " means the fifth Business Day prior to the Facility Termination Date.

" Letter of Credit Notice " has the meaning given to such term in Section 3.2 .

" Letter of Credit Subcommitment " means $45,000,000 or, if less, the Aggregate Commitments at the time of determination, as such amount may be reduced at or prior to such time pursuant to the terms hereof.

" Letters of Credit " is defined in Section 3.1.

" LIBOR Market Index Rate " means, for any day, an interest rate per annum for one month Dollar deposits as reported on Reuters Screen LIBOR01 Page (or any successor page), on such day, or if such day is not a Business Day, then the immediately preceding Business Day (or if not so reported, then as determined by the Administrative Agent from another recognized source or interbank quotation).

" LIBOR Market Index Rate Loan " means a Loan that bears interest at the LIBOR Market Index Rate plus the Applicable Margin.

" LIBOR Rate " means:

(a) with respect to each LIBOR Rate Loan comprising part of the same borrowing for any Interest Period, an interest rate per annum obtained by dividing (i) (y) the rate of interest appearing on Reuters Screen LIBOR01 Page (or any successor page) that represents an average

British Bankers Association Interest Settlement Rate for Dollar deposits (“BBA LIBOR”) or (z) if such rate is not available at such time for any reason, the rate per annum determined by the Administrative Agent to be the rate at which deposits in Dollars for delivery on the first day of such Interest Period in same day funds in the approximate amount of the LIBOR Rate Loan being made, continued or converted and with a term equivalent to such Interest Period would be offered by Wells Fargo’s London Branch to major banks in the London interbank eurodollar market at their request at approximately 11:00 a.m., London time, two Business Days prior to the first day of such Interest Period, by (ii) the amount equal to 1.00 minus the Reserve Requirement (expressed as a decimal) for such Interest Period.

(b) for any interest calculation with respect to a Base Rate Loan on any date, the rate per annum equal to (i) BBA LIBOR, at approximately 11:00 a.m., London time determined two Business Days prior to such date for Dollar deposits being delivered in the London interbank market for a term of one month commencing that day or (ii) if such published rate is not available at such time for any reason, the rate per annum determined by the Administrative Agent to be the rate at which deposits in Dollars for delivery on the date of determination in same day funds in the approximate amount of the Base Rate Loan being made or maintained and with a term equal to one month would be offered by Wells Fargo’s London Branch to major banks in the London interbank eurodollar market at their request at the date and time of determination.

“ LIBOR Rate Loan ” means a Loan which bears interest at the LIBOR Rate plus the Applicable Margin requested by the Borrower pursuant to Section 2.2 .

“ Lien ” means any lien (statutory or other), mortgage, pledge, hypothecation, assignment, deposit arrangement, encumbrance or preference, priority or other security agreement or preferential arrangement of any kind or nature whatsoever (including, without limitation, the interest of a vendor or lessor under any conditional sale, Capitalized Lease or other title retention agreement).

“ Loan” means, with respect to a Lender, any Revolving Loan or Swingline Loan made by such Lender pursuant to Article II (and, in the case of a loan made pursuant to Section 2.2.2 , any conversion or continuation thereof).

“ Loan Document Related Claim” means any claim or dispute (whether arising under Applicable Law, including any “environmental” or similar law, under Contract or otherwise and, in the case of any proceeding relating to any such claim or dispute, whether civil, criminal, administrative or otherwise) in any way arising out of, related to, or connected with, the Loan Documents, the relationships established thereunder or any actions or conduct thereunder or with respect thereto, whether such claim or dispute arises or is asserted before or after the Agreement Date or before or after the Repayment Date.

“ Loan Documents ” means this Agreement and any Notes issued pursuant to Section 2.11 , the Fee Letters, and all other agreements, instruments, documents and certificates now or hereafter executed and delivered to the Administrative Agent or any Lender by or on behalf of the Borrower with respect to this Agreement, in each case as amended, modified, supplemented or restated from time to time.

" Material Adverse Effect " means any effect, resulting from any event or circumstance whatsoever, which will, or is reasonably likely to, have a material adverse effect on the financial condition, operations, assets, business, properties or prospects of the Borrower and its Subsidiaries, taken as a whole, on the ability of the Borrower to perform its obligations under this Agreement, or on the validity or enforceability of this Agreement.

" Material Subsidiary " means at any time with respect to a Person, a Subsidiary, if any, of such Person, the consolidated assets of which exceed at such time 15% of the consolidated assets of such Person and its Subsidiaries, if any, determined on a consolidated basis.

" Maximum Permissible Rate " means, with respect to interest payable on any amount, the rate of interest on such amount that, if exceeded, could, under Applicable Law, result in (i) civil or criminal penalties being imposed on the payee or (ii) the payee's being unable to enforce payment of (or, if collected, to retain) all or any part of such amount or the interest payable thereon.

" Moody's " means Moody's Investors Service, Inc.

" Multiemployer Plan " means any "multiemployer plan" within the meaning of Section 4001(a)(3) of ERISA to which the Borrower or any member of the Controlled Group is making or is obligated to make contributions or has made or been obligated to make contributions.

" Non-Consenting Lender " means a Lender that does not approve any consent, waiver or amendment to any Loan Document that (i) requires the approval of all Lenders (or all Lenders directly affected thereby) under Section 8.2 and (ii) has been approved by the Required Lenders.

" Notes " means, collectively, all of the Revolving Notes and all of the Swingline Notes that may be issued hereunder, and " Note " means any one of the Notes.

" Obligations " means all principal of and interest (including interest accruing after the filing of a petition or commencement of a case by or with respect to the Borrower seeking relief under any applicable federal and state laws pertaining to bankruptcy, reorganization, arrangement, moratorium, readjustment of debts, dissolution, liquidation or other debtor relief, specifically including, without limitation, the Bankruptcy Code and any fraudulent transfer and fraudulent conveyance laws, whether or not the claim for such interest is allowed in such proceeding) on the Loans and Reimbursement Obligations and all fees, expenses, indemnities and other obligations owing, due or payable at any time by the Borrower or any Subsidiary of the Borrower to the Administrative Agent, any Lender, the Swingline Lender, the Issuing Bank or any other Person entitled thereto, under this Agreement or any of the Loan Documents, in each case whether direct or indirect, joint or several, absolute or contingent, matured or unmatured, liquidated or unliquidated, secured or unsecured, and whether existing by contract, operation of law or otherwise.

" OFAC " means the U.S. Department of the Treasury's Office of Foreign Assets Control, and any successor thereto.

" Other Connection Taxes " means, with respect to any Recipient, Taxes imposed as a result of a present or former connection between such Recipient and the jurisdiction imposing such Tax (other than connections arising from such Recipient having executed, delivered, become a party to, performed its obligations under, received payments under, received or perfected a security interest under, engaged in any other transaction pursuant to or enforced any Loan Document, or sold or assigned an interest in any Loan or Loan Document).

" Off-Balance Sheet Liability " of a Person means (i) any repurchase obligation or liability of such Person with respect to accounts or notes receivable sold by such Person, (ii) any liability under any Sale and Leaseback Transaction which is not a Capitalized Lease, (iii) any liability under any so-called "synthetic lease" transaction entered into by such Person, or (iv) any obligation arising with respect to any other transaction which is the functional equivalent of, or takes the place of, borrowing, but which does not constitute a liability on the balance sheets of such Person, but excluding from this clause (iv) Operating Leases.

" Operating Lease " of a Person means any lease of Property (other than a Capitalized Lease) by such Person as lessee which has an original term (including any required renewals and any renewals effective at the option of the lessor) of one year or more.

" Operating Lease Obligations " means, as at any date of determination, the amount obtained by aggregating the present values, determined in the case of each particular Operating Lease by applying a discount rate (which discount rate shall equal the discount rate which would be applied under GAAP if such Operating Lease were a Capitalized Lease) from the date on which each fixed lease payment is due under such Operating Lease to such date of determination, of all fixed lease payments due under all Operating Leases of the Borrower and its Subsidiaries.

" Other Taxes " means all present or future stamp, court or documentary, intangible, recording, filing or similar Taxes that arise from any payment made under, from the execution, delivery, performance, enforcement or registration of, from the receipt or perfection of a security interest under, or otherwise with respect to, any Loan Document, except any such Taxes that are Other Connection Taxes imposed with respect to an assignment (other than an assignment made pursuant to Section 2.21.1).

" Overdue Rate " means (i) in the case of overdue amounts of the principal of a LIBOR Rate Loan, (A) until the last day of the applicable Interest Period during which such Loan became due and payable, the rate otherwise applicable hereunder plus the Applicable Margin plus 2%, and (B) thereafter, the Alternate Base Rate in effect from time to time plus the Applicable Margin plus 2%, and (ii) in the case of all other overdue amounts, the Alternate Base Rate in effect from time to time plus the Applicable Margin plus 2%.

" Participants " is defined in Section 12.2.1 .

" Participant Register " has the meaning given to such term in Section 12.2.1 .

" Passive Arrangers Fee Letter " means the letter to Borrower from BCM and TD dated as of February 15, 2012.

" Patriot Act " is defined in Section 15.5 .

" Payment Date " means the last day of each March, June, September and December.

" PBGC " means the Pension Benefit Guaranty Corporation.

" Pension Plan " means a "pension plan", as such term is defined in section 3(2) of ERISA, which is subject to Title IV of ERISA, and to which the Borrower or any corporation, trade or business that is, along with the Borrower, a member of a Controlled Group, may have liability, including any liability by reason of having been a substantial employer within the meaning of section 4063 of ERISA at any time during the preceding five years, or by reason of being deemed to be a contributing sponsor under section 4069 of ERISA.

" Permitted Commodity Hedging Obligations " means obligations of the Borrower with respect to commodity agreements or other similar agreements or arrangements entered into in the ordinary course of business designed to protect against, or mitigate risks with respect to, fluctuations of commodity prices to which the Borrower is exposed in the conduct of its business so long as (a) the management of the Borrower has determined that entering into such agreements or arrangements are bona fide hedging activities which comply with the Borrower's risk management policies and (b) such agreements or arrangements are not entered into for speculative purposes.

" Person " means any natural person, corporation, firm, joint venture, partnership, limited liability company, association, enterprise, trust or other entity or organization, or any government or political subdivision or any agency, department or instrumentality thereof.

" Pricing Schedule " means Schedule 1.1-A attached hereto.

" Prime Rate " means a rate per annum equal to the prime rate of interest announced from time to time by Wells Fargo, (which is not necessarily the lowest rate charged to any customer), changing when and as said prime rate changes.

" Prior Termination Date " is defined in Section 2.6.3 .

" Property " of a Person means any and all property, whether real, personal, tangible, intangible, or mixed, of such Person, or other assets owned, leased or operated by such Person.

" Purchasers " is defined in Section 12.3.1 .

" Recipient " means (i) the Administrative Agent, (ii) any Lender and (iii) the Issuing Bank, as applicable.

" Refunded Swingline Loans " is defined in Section 2.2.4 .

" Register " is defined in Section 12.3.4 .

" Regulation D " means Regulation D of the Board of Governors of the Federal Reserve System.

" Regulation U " means Regulation U of the Board of Governors of the Federal Reserve System.

“ Regulation X ” means Regulation X of the Board of Governors of the Federal Reserve System.

“ Reimbursement Obligation ” is defined in Section 3.4 .

“ Related Parties ” means, with respect to any Person, such Person’s Affiliates and the partners, directors, officers, employees, agents, trustees, administrators, managers, advisors and representatives of such Person and of such Person’s Affiliates.

“ Release ” means “release”, as such term is defined in CERCLA.

“ Repayment Date ” means the later of (a) the date of the termination of the Commitments (whether as a result of the occurrence of the Facility Termination Date, reduction to zero pursuant to Section 2.5.1 or termination pursuant to Article VIII), and (b) the date of the payment in full of all principal of and interest on the Loans and all other amounts payable or accrued hereunder.

“ Reportable Event ” means a reportable event, as defined in Section 4043 of ERISA and the regulations issued under such section, with respect to a Plan, excluding, however, such events as to which the PBGC has by regulation waived the requirement of Section 4043(a) of ERISA that it be notified within 30 days of the occurrence of such event; provided , however , that a failure to meet the minimum funding standard of Section 412 of the Code and of Section 302 of ERISA shall be a Reportable Event regardless of the issuance of any such waiver of the notice requirement in accordance with either Section 4043(a) of ERISA or Section 412(d) of the Code.

“ Required Lenders ” means Lenders having in the aggregate more than 50.0% of the outstanding Aggregate Commitments or, if the Aggregate Commitments have been terminated, Lenders holding in the aggregate more than 50.0% of the aggregate Credit Exposure; provided that the Commitment of, and the portion of outstanding Loans and Letters of Credit held or deemed held by, any Defaulting Lender shall be excluded for purposes or making a determination of Required Lenders.

“ Reserve Requirement ” means, with respect to any Interest Period, the reserve percentage (expressed as a decimal and rounded upwards, if necessary, to the next higher 1/100 th of 1%) in effect from time to time during such Interest Period, as provided by the Federal Reserve Board, applied for determining the maximum reserve requirements (including, without limitation, basic, supplemental, marginal and emergency reserves) applicable to Wells Fargo under Regulation D with respect to “Eurocurrency liabilities” within the meaning of Regulation D, or under any similar or successor regulation with respect to Eurocurrency liabilities or Eurocurrency funding. The LIBOR Rate shall be adjusted automatically on and as of the effective date of any change in the Reserve Requirement.

“ Resignation Effective Date ” is defined in Section 10.6.1 .

“ Resource Conservation and Recovery Act ” means the Resource Conservation and Recovery Act, 42 U.S.C. Section 690, et seq.

“ Revolving Loan ” is defined in Section 2.1.3 .

"Revolving Note" means a promissory note issued at the request of a Lender pursuant to Section 2.11.4, substantially in the form of Exhibit 2.11.4-A.

"S&P" means Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc.

"Sale and Leaseback Transaction" means any sale or other transfer of Property by any Person with the intent to lease such Property as lessee.

"Sanctioned Country" means a country subject to a sanctions program identified on the list maintained by OFAC and available at http://www.treas.gov/offices/enforcement/ofac/programs/, or as otherwise published from time to time.

"Sanctioned Person" means (i) a Person named on the list of Specially Designated Nationals or Blocked Persons maintained by OFAC available at http://www.treasury.gov/resource-center/sanctions/SDN-List, or as otherwise published from time to time, or (ii) (A) an agency of the government of a Sanctioned Country, (B) an organization controlled by a Sanctioned Country, or (C) a Person resident in a Sanctioned Country, to the extent subject to a sanctions program administered by OFAC.

"SEC" means the Securities and Exchange Commission.

"SEC Disclosure Documents" means all reports on Forms 10K, 10Q, and 8K filed by the Borrower with the SEC.

"Single Employer Plan" means a Plan maintained by the Borrower or any member of the Controlled Group for employees of the Borrower or any member of the Controlled Group.

"Stated Amount" means, with respect to any Letter of Credit at any time, the aggregate amount available to be drawn thereunder at such time (regardless of whether any conditions for drawing could then be met).

"Subsidiary" of a Person means (i) any corporation more than 50% of the outstanding securities having the ordinary voting power of which shall at the time be owned or controlled, directly or indirectly, by such Person or by one or more of its Subsidiaries or by such Person and one or more of its Subsidiaries, or (ii) any partnership, limited liability company, association, joint venture or similar business organization more than 50% of the ownership interests having the ordinary voting power of which shall at the time be so owned or controlled. Unless otherwise expressly provided, all references herein to a "Subsidiary" shall mean a Subsidiary of the Borrower.

"Swingline Commitment" means $45,000,000 or, if less, the Aggregate Commitments at the time of determination, as such amount may be reduced at or prior to such time pursuant to the terms hereof.

"Swingline Exposure" means, with respect to any Lender at any time, its maximum aggregate liability to make Refunded Swingline Loans pursuant to Section 2.2.4 or to purchase participations pursuant to Section 2.2.5 in Swingline Loans that are outstanding at such time.

" Swingline Lender " means Wells Fargo in its capacity as maker of Swingline Loans, and its successors in such capacity.

" Swingline Termination Dat e" means the date that is five Business Days prior to the Repayment Date.

" Swingline Note " means a promissory note issued at the request of a Lender pursuant to Section 2.11.4 , substantially in the form of Exhibit 2.11.3-B .

" Syndication Agent " means BTMU, in its capacity as syndication agent hereunder.

" Taxes " means all present or future taxes, levies, imposts, duties, deductions, withholdings (including backup withholding), assessments, fees or other charges imposed by any Governmental Authority, including any interest, additions to tax or penalties applicable thereto.

" TD " means The TD Bank, N.A., and its successors.

" Transferee " is defined in Section 12.4 .

" Type " means, with respect to any Revolving Loan, its nature as a Base Rate Loan or a LIBOR Rate Loan.

" Unmatured Default " means an event that, but for the lapse of time or the giving of notice, or both, would constitute an Event of Default.

" Unutilized Swingline Commitment " means, with respect to the Swingline Lender at any time, the Swingline Commitment at such time less the aggregate principal amount of all Swingline Loans that are outstanding at such time.

" U.S. Borrower " means any Borrower that is a U.S. Person.

" U.S. Federal Income Taxes " means any U.S. federal Taxes described in Section 871(a) or 881(a) of the Code, or any successor provision (or any withholding with respect to such Taxes).

" U.S. Person " means any Person that is a "United States Person" as defined in section 7701(a)(30) of the Code.

" U.S. Tax Compliance Certificate " has the meaning assigned to such term in Section 2.19.7(ii)(b)(3) .

" Utility " means Washington Gas Light Company, a Virginia and District of Columbia corporation.

" Welfare Plan " means a "welfare plan", as such term is defined in section 3(1) of ERISA.

" Wells Fargo " means Wells Fargo Bank, National Association, and its successors.

" Wells Fargo Securities " means Wells Fargo Securities, LLC, and its successors.

" Withholding Agent " means the Borrower and the Administrative Agent.

1.2 Accounting Terms . Unless otherwise specified herein, all accounting terms used herein shall be interpreted, all accounting determinations hereunder shall be made, and all financial statements required to be delivered hereunder shall be prepared in accordance with, GAAP applied on a basis consistent with the most recent audited consolidated financial statements of the Borrower delivered to the Lenders prior to the closing of this Agreement; provided that if the Borrower notifies the Administrative Agent that it wishes to amend any financial covenant in Section 6.6 to eliminate the effect of any change in GAAP on the operation of such covenant (or if the Administrative Agent notifies the Borrower that the Required Lenders wish to amend Section 6.6 for such purpose), then the Borrower's compliance with such covenant shall be determined on the basis of GAAP as in effect immediately before the relevant change in GAAP became effective, until either such notice is withdrawn or such covenant is amended in a manner satisfactory to the Borrower and the Required Lenders. Notwithstanding the foregoing, for purposes of determining compliance with any covenant (including the computation of any financial covenant) contained herein, Indebtedness of the Borrower and its Subsidiaries shall be deemed to be carried at 100% of the outstanding principal amount thereof, and the effects of FASB ASC 825 on financial liabilities shall be disregarded.

1.3 Other Interpretive Provisions .

(i) Except as otherwise specified herein, all references herein (A) to any Person shall be deemed to include such Person's successors and assigns and (B) to any Applicable Law defined or referred to herein shall be deemed references to such Applicable Law or any successor Applicable Law as the same may have been or may be amended or supplemented from time to time.

(ii) When used in this Agreement, the words "herein", "hereof" and "hereunder" and words of similar import shall refer to this Agreement as a whole and not to any provision of this Agreement, and the words "Article", "Section", "Schedule" and "Exhibit" shall refer to Articles and Sections of, and Schedules and Exhibits to, this Agreement unless otherwise specified.

(iii) Whenever the context so requires, the neuter gender includes the masculine or feminine, the masculine gender includes the feminine, and the singular number includes the plural, and vice versa.

(iv) Any item or list of items set forth following the word "including", "include" or "includes" is set forth only for the purpose of indicating that, regardless of whatever other items are in the category in which such item or items are "included", such item or items are in such category, and shall not be construed as indicating that the items in the category in which such item or items are "included" are limited to such items or to items similar to such items. The word "will" shall be construed to have the same meaning and effect as the word "shall." Unless the context requires otherwise (a) any definition of or reference to any agreement, instrument or other document herein shall be construed as referring to such agreement, instrument or other document as from time to time amended, supplemented or otherwise modified (subject to any restrictions on such amendments, supplements or modifications set forth herein), (b) the words "asset" and "property" shall be construed to have the same meaning and effect and to refer to any and all tangible and intangible assets and properties, including cash, securities, accounts and contract rights.

(v) Each authorization in favor of the Administrative Agent, the Lenders or any other Person granted by or pursuant to this Agreement shall be deemed to be irrevocable and coupled with an interest.

(vi) All references herein to the Lenders or any of them shall be deemed to include the Issuing Bank and the Swingline Lender unless specifically provided otherwise or unless the context otherwise requires.

(vii) Except as otherwise specified herein, all references to the time of day shall be deemed to be to New York City time as then in effect.

ARTICLE II

CREDIT FACILITY

2.1 The Facility .

2.1.1 Availability of Facility . Subject to the terms of this Agreement, the facility is available from the date hereof to the Facility Termination Date, and the Borrower may borrow, repay and reborrow at any time prior to the Facility Termination Date. Unless sooner terminated pursuant to the terms hereof, the Commitments to lend hereunder shall expire on the Facility Termination Date.

2.1.2 Repayment of Facility . Subject to the terms of this Agreement, any outstanding Loans and all other unpaid Obligations shall be paid in full by the Borrower on the Facility Termination Date; provided that if any authorization of any state official or state regulatory authority required under any Applicable Law, for any borrowing of Loans by the Borrower, expires without being extended at any time prior to the Facility Termination Date (and such authorization is required to be in effect at such time in order for the Borrower to continue to have such Loans and other unpaid Obligations outstanding under Applicable Law), then upon the expiration of such authorization, all outstanding Loans and all other unpaid Obligations shall be immediately paid in full by the Borrower.

2.1.3 Revolving Facility . Each Lender severally agrees, subject to and on the terms and conditions of this Agreement, to make loans (each, a “ Revolving Loan ,” and collectively, the “ Revolving Loans ”) to the Borrower, from time to time on any Business Day during the period from and including the Agreement Date to but not including the Facility Termination Date, in an aggregate principal amount at any time outstanding not exceeding its Commitment; provided that no borrowing of Revolving Loans shall be made if, immediately after giving effect thereto (and to any concurrent repayment of Swingline Loans with proceeds of Revolving Loans made pursuant to such borrowing), (i) the amount of all outstanding Credit Exposure of any Lender exceed such Lender’s Commitment or (ii) the aggregate principal amount of all outstanding Credit Exposure exceed the Aggregate Commitments. Subject to and on the terms and conditions of this Agreement, the Borrower may borrow, repay and reborrow Revolving Loans.

2.1.4 Swingline Facility. The Swingline Lender agrees, subject to and on the terms and conditions of this Agreement, to make loans (each, a "Swingline Loan," and collectively, the "Swingline Loans") to the Borrower, from time to time on any Business Day during the period from the Agreement Date to but not including the Swingline Termination Date (or, if earlier, the Facility Termination Date), in an aggregate principal amount at any time outstanding not exceeding the Swingline Commitment. Swingline Loans may be made even if the aggregate principal amount of Swingline Loans outstanding at any time, when added to the aggregate Credit Exposure of the Swingline Lender in its capacity as a Lender outstanding at such time, would exceed the Swingline Lender's own Commitment at such time, but provided that no borrowing of Swingline Loans shall be made if, immediately after giving effect thereto (i) the amount of all outstanding Credit Exposure of any Lender exceed such Lender's Commitment or (ii) the aggregate principal amount of all outstanding Credit Exposure exceeds the Aggregate Commitments, and provided further that the Swingline Lender shall not make any Swingline Loan if any Lender is at that time a Defaulting Lender, unless the Swingline Lender has entered into arrangements satisfactory to the Swingline Lender (in its sole discretion) with the Borrower or such Lender to eliminate the Swingline Lender's actual or potential Fronting Exposure (after giving effect to Section 2.22.1(iv)) with respect to the Defaulting Lender arising from either the Swingline Loan then proposed to be made or that the Swingline Loan and all other Swingline Loans as to which the Swingline Lender has actual or potential Fronting Exposure, as it may elect in its sole discretion. Subject to and on the terms and conditions of this Agreement, the Borrower may borrow, repay (including by means of a borrowing of Revolving Loans pursuant to Section 2.2.3) and reborrow Swingline Loans. All Swingline Loans shall bear interest at the LIBOR Market Index Rate plus the Applicable Margin.

2.2 Loans.

2.2.1 Types of Loans. The Revolving Loans may be made as, and from time to time continued as or converted to, Base Rate Loans or LIBOR Rate Loans (each a "Type" of Loan), or a combination thereof, selected by the Borrower in accordance with Section 2.2.2. The Swingline Loans shall be made and maintained as LIBOR Market Index Rate Loans at all times and may not be converted into or continued as LIBOR Rate Loans or Base Rate Loans under Section 2.2.7.

2.2.2 Borrowing of Revolving Loans. In order to request Revolving Loans (other than (i) borrowings of Swingline Loans, which shall be made pursuant to Section 2.2.3, (ii) borrowings for the purpose of repaying Refunded Swingline Loans, which shall be made pursuant to Section 2.2.4, (iii) borrowings for the purpose of paying unpaid Reimbursement Obligations, which shall be made pursuant to Section 3.4, and (iv) borrowings involving continuations or conversions of outstanding Loans, which shall be made pursuant to Section 2.2.7), the Borrower shall give the Administrative Agent irrevocable written notice (a "Borrowing Notice"), not later than 11:00 a.m. on the requested Borrowing Date of each Base Rate Loan and at least three Business Days before the requested Borrowing Date for each LIBOR Rate Loan. A Borrowing Notice shall be in the form of Exhibit 2.2.2 hereto and shall specify:

(i) the requested Borrowing Date, which shall be a Business Day, of such Loan,

(ii) the aggregate amount of such Loan,

(iii) the Type of Loan selected, and

(iv) in the case of each LIBOR Rate Loan, the Interest Period applicable thereto (which may not end after the Facility Termination Date).

Each LIBOR Rate Loan shall be in the minimum amount of $5,000,000 (and any whole multiple of $1,000,000 in excess thereof), and each Base Rate Loan shall be in the minimum amount of $1,000,000 (and any whole multiple of $1,000,000 in excess thereof); provided , however , any Base Rate Loan may be in the amount of the unused Aggregate Commitments. If the Borrower shall have failed to designate the Type of Loans selected, the Borrower shall be deemed to have requested Base Rate Loans. If the Borrower shall have failed to select the duration of the Interest Period to be applicable to any LIBOR Rate Loans requested, then the Borrower shall be deemed to have selected an Interest Period with a duration of one month.

Upon receipt of any such notice, the Administrative Agent shall promptly notify each Lender of the contents thereof and of the amount and Type of each Loan to be made by such Lender on the requested date specified therein. To the extent such Lenders have made such amounts available to the Administrative Agent as provided in Section 2.3 , the Administrative Agent will make the aggregate of such amounts available to the Borrower in like funds as received by the Administrative Agent.

2.2.3 Borrowing of Swingline Loans . In order to request Swingline Loans, the Borrower shall give the Administrative Agent (and the Swingline Lender, if the Swingline Lender is not also the Administrative Agent) irrevocable written notice (a " Swingline Borrowing Notice ") not later than 11:00 a.m., on the date of requested Borrowing Date. A Borrowing Notice shall be in the form of Exhibit 2.2.3 hereto and shall specify:

(i) the requested Borrowing Date, which shall be a Business Day, of such Loan, and

(ii) the aggregate amount of such Loan.

Each Swingline Loan (x) shall be in the minimum amount of $100,000 (and a whole multiple of $100,000 if in excess thereof (or if less, in the amount of the Unutilized Swingline Commitment)) and (y) shall be due and payable on the earlier of (A) the Swingline Termination Date and (B) within ten Business Days of such Loan being made. To the extent the Swingline Lender has made such amount available to the Administrative Agent as provided in Section 2.3 , the Administrative Agent will make such amount available to the Borrower. Immediately upon the making of a Swingline Loan, each Lender shall be deemed to, and hereby irrevocably and unconditionally agrees to, purchase from the Swingline Lender a risk participation in such Swingline Loan in an amount equal to the product of such Lender's Applicable Percentage times the amount of such Swingline Loan.

2.2.4 Refunded Swingline Loans . With respect to any outstanding Swingline Loans, the Swingline Lender may at any time (whether or not an Event of Default has occurred and is continuing) in its sole and absolute discretion, and is hereby authorized and empowered by the Borrower to, cause a Borrowing of Revolving Loans to be made for the purpose of repaying such Swingline Loans by delivering to the Administrative Agent (if the Administrative Agent is not also the Swingline Lender) and each other Lender (on behalf of, and with a copy to, the Borrower), not later than 11:00 a.m. on the proposed Borrowing Date therefor, a notice (which shall be deemed to be a Borrowing Notice given by the Borrower) requesting the Lenders to make Revolving Loans (which shall be made initially as Base Rate Loans) on such Borrowing Date in an aggregate amount equal to the amount of such Swingline Loans (the " Refunded Swingline Loans ") outstanding on the date such notice is given that the Swingline Lender requests to be repaid. To the extent the Lenders have made such amounts available to the Administrative Agent as provided in Section 2.3 , the Administrative Agent will make the aggregate of such amounts available to the Swingline Lender in like funds as received by the Administrative Agent, which shall apply such amounts in repayment of the Refunded Swingline Loans. Notwithstanding any provision of this Agreement to the contrary, on the relevant Borrowing Date, the Refunded Swingline Loans (including the Swingline Lender's ratable share thereof, in its capacity as a Lender) shall be deemed to be repaid with the proceeds of the Revolving Loans made as provided above (including a Revolving Loan deemed to have been made by the Swingline Lender), and such Refunded Swingline Loans deemed to be so repaid shall no longer be outstanding as Swingline Loans but shall be outstanding as Revolving Loans. If any portion of any such amount repaid (or deemed to be repaid) to the Swingline Lender shall be recovered by or on behalf of the Borrower from the Swingline Lender in any bankruptcy, insolvency or similar proceeding or otherwise, the loss of the amount so recovered shall be shared ratably among all the Lenders in the manner contemplated by Section 2.3 .

2.2.5 Lender Participation in Swingline Loans . If, as a result of any bankruptcy, insolvency or similar proceeding with respect to the Borrower, Revolving Loans are not made pursuant to Section 2.2.4 in an amount sufficient to repay any amounts owed to the Swingline Lender in respect of any outstanding Swingline Loans, or if the Swingline Lender is otherwise precluded for any reason from giving a notice on behalf of the Borrower as provided for hereinabove, each Lender, upon one Business Day's prior notice from the Swingline Lender, shall fund its risk participation in such outstanding Swingline Loans by making available to the Administrative Agent an amount equal to its Applicable Percentage of the unpaid amount thereof together with accrued interest thereon. To the extent the Lenders have made such amounts available to the Administrative Agent as provided Section 2.3 , the Administrative Agent will make the aggregate of such amounts available to the Swingline Lender in like funds as received by the Administrative Agent. In the event any such Lender fails to make available to the Administrative Agent the amount of such Lender's participation as provided in this Section 2.2.5 , the Swingline Lender shall be entitled to recover such amount on demand from such Lender, together with interest thereon for each day from the date such amount is required to be made available for the account of the Swingline Lender until the date such amount is made available to the Swingline Lender at the Federal Funds Effective Rate for the first three Business Days and thereafter at the Alternative Base Rate. Promptly following its receipt of any payment by or on behalf of the Borrower in respect of a Swingline Loan, the Swingline Lender will pay to each Lender that has acquired a participation therein such Lender's Applicable Percentage of such payment.

2.2.6 Notwithstanding any provision of this Agreement to the contrary, the obligation of each Lender (other than the Swingline Lender) to make Revolving Loans for the purpose of repaying any Refunded Swingline Loans pursuant to Section 2.2.4 and each such

Lender's obligation to purchase a participation in any unpaid Swingline Loans pursuant to Section 2.2.5 shall be absolute and unconditional and shall not be affected by any circumstance or event whatsoever, including, without limitation, (i) any set-off, counterclaim, recoupment, defense or other right that such Lender may have against the Swingline Lender, the Administrative Agent, the Borrower or any other Person for any reason whatsoever, (ii) the occurrence or continuance of any Unmatured Default or Event of Default, (iii) the failure of the amount of such borrowing of Revolving Loans to meet the minimum borrowing amount specified in Section 2.2.2 , or (iv) the failure of any conditions set forth in Section 4.2 or elsewhere herein to be satisfied.

2.2.7 Conversion and Continuation of Outstanding Loans .

(i) Each Base Rate Loan shall continue as a Base Rate Loan unless and until such Base Rate Loan is either converted into a LIBOR Rate Loan in accordance with this Section 2.2.7 or repaid in accordance with Section 2.5 . Each LIBOR Rate Loan shall continue as a LIBOR Rate Loan until the end of the then applicable Interest Period therefor, at which time such LIBOR Rate Loan shall be automatically converted into a Base Rate Loan unless the Borrower shall have given the Administrative Agent a Conversion/Continuation Notice in the manner set forth below requesting that, at the end of such Interest Period, such LIBOR Rate Loan continue as a LIBOR Rate Loan for the same or another Interest Period. The Borrower may elect from time to time to convert all or any part of a Base Rate Loan into a LIBOR Rate Loan. The Borrower shall give the Administrative Agent irrevocable notice in the form of Exhibit 2.2.7 (a " Conversion/Continuation Notice ") of each conversion of a Base Rate Loan into a LIBOR Rate Loan, or continuation of a LIBOR Rate Loan, not later than 11:00 a.m. at least three Business Days prior to the date of the requested conversion or continuation, specifying:

(a) the requested date, which shall be a Business Day, of such conversion or continuation,

(b) the aggregate amount and Type of the Loan which is to be converted or continued, and

(c) the amount of such Loan(s) which is to be converted or continued as a LIBOR Rate Loan and the duration of the Interest Period applicable thereto.

Each conversion of a LIBOR Rate Loan into a Base Rate Loan shall involve a minimum amount of $3,000,000 (and a whole multiple of $1,000,000, if in excess thereof). Each conversion of a Base Rate Loan into a LIBOR Rate Loan shall involve a minimum amount of $5,000,000 (and a whole multiple of $1,000,000 if in excess thereof). No partial conversion of LIBOR Rate Loans made pursuant to a single Borrowing Notice shall reduce the outstanding principal amount of such LIBOR Rate Loans to less than $5,000,000 (or to any greater amount not a whole multiple of $1,000,000 in excess thereof). Except as otherwise provided in Section 2.18.6 , LIBOR Rate Loans may be converted into Base Rate Loans only on the last day of the Interest Period Applicable thereto (and in any event, if a LIBOR Rate Loan is converted into a Base Rate Loan on any day other than the last day of the Interest Period applicable thereto, the Borrower will pay, upon such conversion, all amounts required under Section 2.18.1 to be paid as a consequence thereof).

Upon receipt of any such notice, the Administrative Agent shall promptly notify each Lender of (x) the contents thereof, (y) the amount and Type and, in the case of LIBOR Rate Loans, the last day of the applicable Interest Period of each Loan to be converted or continued by such Lender and (z) the amount and Type or Types of Loans into which such Loans are to be converted or as which such Loan are to be continued.

(ii) Notwithstanding anything to the contrary contained in this Section 2.2.7 , during an Event of Default, the Administrative Agent may notify the Borrower that Loans may only be converted into or continued as Loans of certain specified Types.

2.3 Funding by Lenders; Disbursement to the Borrower .

2.3.1 Funding by Lenders . Not later than 1:00 p.m. on each requested Borrowing Date, each Lender shall, if it has received the notice contemplated by Sections 2.2.2 , 2.2.3 , 2.2.4 or 2.2.5 on or prior to 12:00 noon on such date, in the case of Base Rate Loans, or on or prior to its close of business on the third Business Day before such date, in the case of LIBOR Rate Loans, make available to the Administrative Agent, in Dollars in funds immediately available to the Administrative Agent at its address specified pursuant to Article XIII , the amount of Loans to be made by such Lender on such date.

2.3.2 Disbursement to the Borrower . Upon satisfaction of the applicable conditions set forth in Section 4.2 (and, if such Borrowing is on the Agreement Date, Section 4.1), Loans shall be disbursed by the Administrative Agent not later than 3:30 p.m. on the date specified therefor by credit to an account of the Borrower at the Administrative Agent at its address specified pursuant to Article XIII or in such other manner as may have been specified to and as shall be reasonably acceptable to the Administrative Agent, in each case in Dollars in funds immediately available to the Borrower, as the case may be.

2.4 Fees . The Borrower agrees to pay:

2.4.1 Arranger Fees. (i) To Wells Fargo Securities and BTMU, for their own respective accounts, on the Agreement Date, the fees required under the Active Arrangers Fee Letter and (ii) BCM and TD, for their respective accounts, on the Agreement Date, the fees required under the Passive Arrangers Fee Letter;

2.4.2 Facility Fee . To the Administrative Agent for the account of each Lender a facility fee at a per annum rate equal to the Facility Fee Rate on the average daily amount of such Lender's Commitment (whether used or unused) from the date hereof to and including the Repayment Date (the " Facility Fee "), payable on the last day of each calendar quarter hereafter and on the Repayment Date.

2.4.3 Letter of Credit Fees . To the Administrative Agent, for the account of each Lender, a letter of credit fee for each calendar quarter (or portion thereof) in respect of all Letters of Credit outstanding during such quarter, at a rate per annum equal to the Applicable Margin then in effect during such quarter for LIBOR Rate Loans on such Lender's pro rata share of the daily average aggregate Stated Amount of such Letters of Credit, payable in arrears on (i) the last Business Day of each calendar quarter, beginning with the first such day to occur after the Agreement Date, and (ii) on the later of the Facility Termination Date and the date of termination of the last outstanding Letter of Credit; provided , however , that any letter of credit fees otherwise payable for the account of a Defaulting Lender with respect to any Letter of Credit as to which such Defaulting Lender has not provided Cash Collateral satisfactory to the Issuing Bank pursuant to Section 3.1.1 shall be payable, to the maximum extent permitted by Applicable Law, to the other Lenders in accordance with the upward adjustments in their respective pro rata shares allocable to such Letter of Credit pursuant to Section 2.22.1(iv) , with the balance of such fee, if any, payable to the Issuing Bank for its own account;

2.4.4 Letter of Credit Facing Fee . To each Issuing Bank, for its own account, a facing fee for each calendar quarter (or portion thereof) on the daily average aggregate Stated Amount of all Letters of Credit issued by such Issuing Bank outstanding during such quarter, at a per annum rate separately agreed to between each Issuing Bank and the Borrower (each an " LC Fee "), payable in arrears (i) on the last Business Day of each calendar quarter, beginning with the first such day to occur after the Agreement Date, and (ii) on the later of the Facility Termination Date and the date of termination of the last outstanding Letter of Credit;

2.4.5 Letter of Credit Customary Fees . To each Issuing Bank, for its own account, such commissions, transfer fees and other fees and charges incurred in connection with the issuance and administration of each Letter of Credit issued by it as are customarily charged from time to time by such Issuing Bank for the performance of such services in connection with similar letters of credit, or as may be otherwise agreed to by such Issuing Bank, but without duplication of amounts payable under Section 2.4.2 ; and

2.4.6 Administrative Fee . To the Administrative Agent, for its own account, the annual administrative fee described in the Administrative Fee Letter, on the terms, in the amount and at the times set forth therein.

None of the fees payable under this Section 2.4 shall be refundable in whole or in part.

2.5 Reductions in Aggregate Commitments; Increases in Aggregate Commitments .

2.5.1 Reductions . The Borrower may permanently reduce the Aggregate Commitments, in whole or in part, ratably among the Lenders in an amount equal to $5,000,000 ($500,000 in the case of the Unutilized Swingline Commitment) or a whole multiple of $1,000,000 in excess thereof (or $100,000 in the case of the Unutilized Swingline Commitment) upon at least three Business Days' written notice to the Administrative Agent (and in the case of a termination or reduction of the Unutilized Swingline Commitment, the Swingline Lender), which notice shall specify the amount of any such reduction; provided , however , that the amount of the Aggregate Commitments may not be reduced below the aggregate outstanding Credit Exposure. Upon receipt of any such notice, the Administrative Agent (or Swingline Lender) shall promptly notify each Lender of the contents thereof and the amount to which such Lender's Commitment is to be reduced. All accrued Facility Fees shall be payable on the effective date of any termination of the obligations of the Lenders to make Loans hereunder. The amount of any termination or reduction made under this Section 2.5.1 may not thereafter be reinstated.

2.5.2 Increases . At any time following the Agreement Date and prior to the Facility Termination Date, the Aggregate Commitments may, at the option of the Borrower, be increased by a total amount not in excess of $100,000,000, either by one or more then-existing Lenders increasing their Commitments or by new Lenders establishing such additional Commitments (each such increase by either means, a " Commitment Increase ", and each such Lender increasing its Commitment or new Lender, an " Additional Commitment Lender "); provided that (i) each new Lender shall be reasonably acceptable to the Administrative Agent, (ii) no Unmatured Default or Event of Default shall exist immediately prior to or after the effective date of such Commitment Increase, (iii) all representations and warranties made by the Borrower in this Agreement as of the date of such Commitment Increase are true and correct in all material respects, (iv) each such Commitment Increase shall be in an aggregate amount not less than $10,000,000 or a whole multiple of $5,000,000 in excess thereof, or, if less, the maximum remaining amount that the Aggregate Commitments may be increased pursuant to this Section 2.5.2 , and (v) no such Commitment Increase shall become effective unless and until the Borrower, the Administrative Agent and the Additional Commitment Lenders shall have executed and delivered an agreement substantially in the form of Exhibit 2.5.2 (a " Commitment Increase Supplement "). On the effective date of such Commitment Increase, each Additional Commitment Lender shall purchase, by assignment, from each other existing Lender the portion of such other Lender's Credit Exposure outstanding at such time such that, after giving effect to such assignments, the respective aggregate amount of Credit Exposure of each Lender shall be equal to such Lender's Applicable Percentage (as adjusted pursuant hereto) of the aggregate Credit Exposure outstanding. The purchase price for the Loans so assigned shall be the principal amount of the Loans so assigned plus the amount of accrued and unpaid interest thereon on the date of assignment. Upon payment of such purchase price, each Lender shall be automatically deemed to have sold and made such an assignment to such Additional Commitment Lender and shall, to the extent of the interest assigned, be released from its obligations under this Agreement, and such Additional Commitment Lender shall be automatically deemed to have purchased and assumed such an assignment from each other Lender and, if not already a Lender hereunder, shall be a party hereto and, to the extent of the interest assigned, have the rights and obligations of a Lender under this Agreement.

2.6 Extension Option. After the first anniversary of the Agreement, and then no earlier than 60 days and no later than 30 days prior to each anniversary of the Agreement Date, but on no more than two occasions, the Borrower may, by written notice to the Administrative Agent, request that the Lenders extend the Facility Termination Date for an additional year. Any election by a Lender to extend the term of its Commitment pursuant to such a request shall be at such Lender's sole discretion and subject to such credit evaluation as such Lender may determine.

2.6.1 No extension pursuant to this Section 2.6 shall become effective unless agreed to in writing not later than 15 days prior to the relevant anniversary of the Agreement Date by Lenders then holding more than 50% of the Commitments.

2.6.2 In the event that Lenders then holding more than 50% of the Commitments but less than 100% of the Commitments shall agree to an extension requested pursuant to this Section 2.6 , the Borrower shall be entitled to propose a new Lender or Lenders (which shall be reasonably acceptable to the Administrative Agent, the Swingline Lender and the Issuing Banks), or an increase in the Commitment or Commitments of a then existing Lender or Lenders, whose new or increased Commitments (in an aggregate amount not in excess of the Commitments of the Lenders who did not agree to extend) shall be in effect during the extension period so agreed.

2.6.3 Unless a Lender which does not agree to extend its Commitment shall be replaced pursuant to Section 2.6.4 , the Commitment of such Lender shall continue in full force and effect until the Facility Termination Date to which it has agreed (each a " Prior Termination Date ").

2.6.4 In the event that an existing Lender shall not agree to extend its Commitment pursuant to a request by the Borrower, the Borrower shall be entitled to replace such Lender with another Lender or and/or an Eligible Assignee that shall assume the then Commitment of such existing Lender and shall agree to the extension requested. Any Eligible Assignee (if not already a Lender hereunder) shall become a party to this agreement as a Lender pursuant to a joinder agreement in form and substance reasonably satisfactory to the Administrative Agent and the Borrower. In the event of such a replacement, such existing Lender shall assign to such replacement Lender the outstanding Loans of such existing Lender for a purchase price equal to the principal amount of the Loans so assigned, plus the amount of accrued and unpaid interest thereon to the date of such assignment, and such replacement Lender shall acquire (and fund as appropriate) its full pro rata share of all Loans and participations in Letters of Credit and Swingline Loans in accordance with its Applicable Percentage.

2.6.5 An extension of the Facility Termination Date pursuant to this Section 2.6 shall only become effective upon the receipt by the Administrative Agent of a certificate (the statements contained in which shall be true) of a duly authorized officer of the Borrower stating that both before and after giving effect to such extension of the Facility Termination Date (i) no Unmatured Default or Event of Default has occurred and is continuing and (ii) all representations and warranties made by the Borrower under this Agreement are true and correct in all material respects on and as of the date such extension is made.

2.6.6 Effective on and after the Prior Termination Date, (i) each of the Lenders who does not agree to extend its Commitment shall be automatically released from their respective participations and Reimbursement Obligations under Section 3.4 with respect to any outstanding Letters of Credit and (ii) the participations and Reimbursement Obligations of each Lender (other than the Lenders who do not agree to extend their Commitments) shall be automatically adjusted to equal such Lender's revised Applicable Percentage of such outstanding Letters of Credit.

2.7 Repayments; Optional Principal Prepayments .

(a) Each Loan shall mature and become due and payable, and shall be repaid by the Borrower, in full on the day one year after the date such Loan was made, unless the Borrower's Board of Directors, by a written resolution, has authorized such Loan to be outstanding for a term in excess of one year, in which case such Loan shall mature and become due and payable, and shall be repaid by the Borrower, in full on the date fixed by such written resolution, but in no event later than on the Facility Termination Date.

(b) The Borrower may from time to time pay, without penalty or premium, all outstanding Loans, or any portion of the outstanding Loans, on any Business Day upon notice to the Administrative Agent one Business Day prior to each intended prepayment of Alternative Base Rate Loans and three Business Days prior to each intended prepayment of LIBOR Rate Loans; provided that (i) each partial payment of LIBOR Rate Loans shall be in the minimum amount of $5,000,000 (and a whole multiple of $1,000,000 if in excess thereof), and each partial payment of Base Rate Loans shall be in the minimum amount of $3,000,000 (and a whole multiple of $1,000,000 if in excess thereof) ($100,000 and $100,000, respectively, in the case of Swingline Loans), (ii) no partial payment of LIBOR Rate Loans made pursuant to a single borrowing shall reduce the aggregate outstanding principal amount of the remaining LIBOR Rate Loans under such borrowing to less than $5,000,000 (and a whole multiple of $1,000,000 if in excess thereof), and (iii) unless made together with all amounts required under Section 2.18 .1 to be paid as a consequence of such prepayment, a prepayment of a LIBOR Rate Loan may be made only on the last day of the Interest Period applicable thereto. Each such notice of prepayment shall be in the form of Exhibit 2.7 and shall specify (i) the date such prepayment is to be made and (ii) the amount and Type of the Loans to be prepaid and, in the case of LIBOR Rate Loans, the last day of the applicable Interest Period of the LIBOR Rate Loans to be prepaid. Upon receipt of any such notice, the Administrative Agent shall promptly notify each Lender of the contents thereof and the amount and Type of the Loans to be prepaid and, in the case of LIBOR Rate Loans, the last day of the applicable Interest Period of each LIBOR Rate Loan of such Lender to be prepaid. Amounts to be prepaid shall irrevocably be due and payable on the date specified in the applicable notice of prepayment, together with interest thereon as provided in Section 2.13 .

2.8 Changes in Interest Rate, etc . Each Base Rate Loan shall bear interest on the outstanding principal amount thereof, for each day from and including the date such Loan is made or is converted from a LIBOR Rate Loan into a Base Rate Loan pursuant to Section 2.2.7 to but excluding the date it becomes due or is converted into a LIBOR Rate Loan pursuant to Section 2.2.7 hereof, at a rate per annum equal to the Base Rate plus the Applicable Margin for such day. Each LIBOR Rate Loan shall bear interest on the outstanding principal amount thereof from and including the first day of the Interest Period applicable thereto to (but not including) the last day of such Interest Period at the applicable LIBOR Rate plus the Applicable Margin. No Interest Period may end after the Facility Termination Date.

2.9 Rates Applicable After Default . During the continuance of an Unmatured Default the Required Lenders may, at their option, by notice to the Borrower (which notice may be revoked at the option of the Required Lenders notwithstanding any provision of Section 8.2 requiring unanimous consent of the Lenders to changes in interest rates), declare that no Loan may be made as, converted into, or continued as a LIBOR Rate Loan. During the continuance of an Event of Default the Required Lenders may, at their option, by notice to the Borrower (which notice may be revoked at the option of the Required Lenders notwithstanding any provision of Section 8.2 requiring unanimous consent of the Lenders to changes in interest rates), declare that each Loan and all other amounts payable under the Loan Documents shall bear interest at the Overdue Rate; provided that, during the continuance of an Event of Default under Sections 0 , 0 or 0, any amount payable under the Loan Documents not paid when due (whether at maturity, by reason of notice of prepayment or otherwise) shall bear interest at a rate per annum equal to the Overdue Rate without any election or action on the part of the Administrative Agent or any Lender.

2.10 Method of Payment .

2.10.1 Payments by Borrower . All payments of the Obligations hereunder and under the other Loan Documents shall be made, observed or performed, without setoff, deduction, or counterclaim (whether sounding in tort, contract or otherwise) or Tax. All amounts payable for the account of the Administrative Agent shall be paid in immediately available funds to the Administrative Agent at the Administrative Agent's address specified pursuant to Article XIII , or at any other Lending Installation of the Administrative Agent specified in writing by the Administrative Agent to the Borrower, by noon on the date when due and shall be applied ratably by the Administrative Agent among the Lenders. All amounts payable for the account of any Lender under the Loan Documents shall, in the case of payments on account of principal of or interest on the Loans or fees, be made to the Administrative Agent at the Administrative Agent's address specified pursuant to Article XIII and, in the case of all other payments, be made directly to such Lender at its address specified pursuant to Article XIII or at such other address as such Lender may designate by notice to the Borrower.

2.10.2 Payments to Lenders . Each payment delivered to the Administrative Agent for the account of any Lender shall be delivered promptly by the Administrative Agent to such Lender in the same type of funds that the Administrative Agent received at its address specified pursuant to Article XIII or at any Lending Installation specified in a notice received by the Administrative Agent from such Lender. Notwithstanding the foregoing or any contrary provision hereof, if any Lender shall fail to make any payment required to be made by it hereunder to the Administrative Agent, any Issuing Bank or the Swingline Lender, then the Administrative Agent may, in its discretion, apply any amounts thereafter received by the Administrative Agent for the account of such Lender to satisfy such Lender's obligations to the Administrative Agent, such Issuing Bank or the Swingline Lender, as the case may be, until all such unsatisfied obligations are fully paid. If the Administrative Agent shall not have made a required distribution to the appropriate Lenders as required hereinabove after receiving a payment for the account of such Lenders, the Administrative Agent will pay to each such Lender, on demand, its ratable share of such payment with interest thereon at the Federal Funds Effective Rate for each day from the date such amount was required to be disbursed by the Administrative Agent until the date repaid to such Lender. The Administrative Agent will distribute to each Issuing Bank like amounts relating to payments made to the Administrative Agent for the account of such Issuing Bank in the same manner, and subject to the same terms and conditions, as set forth hereinabove with respect to distributions of amounts to the Lenders.

2.10.3 Authorization to Charge the Borrower's Accounts . The Borrower hereby authorizes the Administrative Agent and each Lender, if and to the extent any amount payable by the Borrower under the Loan Documents (whether payable to such Person or to any other Person that is the Administrative Agent or a Lender) is not otherwise paid when due, to charge such amount against any or all of the accounts of the Borrower with such Person or any of its Affiliates (whether maintained at a branch or office located within or without the United States), with the Borrower remaining liable for any deficiency. Any Lender charging an amount against an account of the Borrower shall comply with Section 11.2 and provide notice thereof to the Borrower, within a reasonable time thereafter, which notice shall include a description in reasonable detail of such action.

2.11 Evidence of Indebtedness .

2.11.1 Lenders' Evidence of Indebtedness . Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Loan made by such Lender from time to time, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

2.11.2 Administrative Agent's Evidence of Indebtedness . The Administrative Agent shall also maintain the Register of accounts pursuant to Section 12.3.4 in which it will record (a) the amount of each Loan made hereunder, the Type thereof and the Interest Period with respect thereto, (b) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (c) the amount of any sum received by the Administrative Agent hereunder from the Borrower and each Lender's share thereof.

2.11.3 Effect of Entries . The entries maintained in the accounts and records maintained pursuant to Sections 2.11.1 and 2.11.2 above shall be prima facie evidence of the existence and amounts of the Obligations therein recorded; provided , however , that the failure of the Administrative Agent or any Lender to maintain such accounts and records or any error therein shall not in any manner affect the obligation of the Borrower to repay the Obligations in accordance with their terms.

2.11.4 Notes Upon Request . Any Lender may request that its Loans be evidenced by Notes. In such event, the Borrower shall prepare, execute and deliver to such Lender (a) in the case of Revolving Loans, a Revolving Note in the form of Exhibit 2.11.3-A , payable to the order of such Lender and (b) in the case of Swingline Loans, a Swingline Note in the form of Exhibit 2.11.3-B . Thereafter, the Loans represented by such Note and interest thereon shall at all times (including after any assignment pursuant to Section 12.3) be evidenced by a Note payable to the order of the payee named therein or any assignee pursuant to Section 12.3 , except to the extent that any such Lender or assignee subsequently returns any such Note for cancellation and requests that such Loans once again be evidenced as described in paragraphs 2.11.1 and 2.11.1 above.

2.12 Telephonic Notices . The Borrower hereby authorizes the Lenders and the Administrative Agent to extend, convert, or continue Loans; to effect selections of Types of Loans; and to transfer funds based on telephonic notices made by any Person or Persons the Administrative Agent or any Lender in good faith believes to be acting on behalf of the Borrower, it being understood that the foregoing authorization is specifically intended to allow Borrowing Notices, Swingline Borrowing Notices, and Conversion/Continuation Notices to be given telephonically. The Borrower agrees to deliver promptly to the Administrative Agent a written confirmation, if such confirmation is requested by the Administrative Agent or any Lender, of each telephonic notice signed by an Authorized Officer. If the written confirmation differs in any material respect from the action taken by the Administrative Agent and the Lenders, the records of the Administrative Agent and the Lenders shall govern absent manifest error.

2.13 Interest Payment Dates; Interest and Fee Basis . Interest accrued on each Base Rate Loan and each LIBOR Market Index Rate Loan shall be payable on each Payment Date, commencing with the first such date to occur after the Agreement Date, on any date on which the Base Rate Loan or LIBOR Market Index Rate Loan is prepaid, whether due to acceleration or otherwise, and at maturity. Interest accrued on that portion of the outstanding principal amount of any Base Rate Loan converted into a LIBOR Rate Loan on a day other than a Payment Date shall be payable on the date of conversion. Interest accrued on each LIBOR Rate Loan shall be payable on the last day of its applicable Interest Period, on any date on which the Loan is prepaid, whether by acceleration or otherwise, and at maturity. Interest accrued on each LIBOR Rate Loan having an Interest Period longer than three months shall also be payable on the last day of each three month interval during such Interest Period. Interest, Facility Fees and LC Fees shall be calculated for actual days elapsed on the basis of a 360 day year, except that interest calculated based on the Prime Rate shall be calculated for actual days elapsed on the basis of a 365, or when appropriate 366, day year. Interest shall be payable for the day a Loan is made but not for the day of any payment on the amount paid if payment is received prior to noon (local time) at the place of payment. Whenever any payment to the Administrative Agent or any Lender under the Loan Documents would otherwise be due on a day that is not a Business Day, such payment shall instead be due on the next succeeding Business Day; provided , however , that if such next succeeding Business Day falls in a new calendar month, such payment shall instead be due on the immediately preceding Business Day. If the date any payment under the Loan Documents is due is extended (whether by operation of any Loan Document, Applicable Law or otherwise), such payment shall bear interest for such extended time at the rate of interest applicable hereunder. Interest at the Overdue Rate shall be payable on demand.

2.14 Notification of Loans, Interest Rates, Prepayments and Commitment Reductions . Promptly after receipt thereof, the Administrative Agent will notify each Lender of the contents of each Aggregate Commitments reduction notice, Borrowing Notice, Swingline Notice, Conversion/Continuation Notice, Letter of Credit Notice, Commitment Increase Supplement and repayment notice received by it hereunder. The Administrative Agent will notify each Lender of the LIBOR Rate or Alternate Base Rate applicable to each Loan promptly upon determination of such interest rate and will give each Lender prompt notice of each change in the Alternate Base Rate. The Administrative Agent will notify each Lender of any request by the Borrower pursuant to Section 2.6 to extend the Facility Termination Date.

2.15 Lending Installations . Each Lender may book its Loans at any Lending Installation selected by such Lender and may change its Lending Installation from time to time. All terms of this Agreement shall apply to any such Lending Installation and any Notes issued hereunder shall be deemed held by each Lender for the benefit of any such Lending Installation. Each Lender may, by written notice to the Administrative Agent and the Borrower in accordance with Article XIII , designate replacement or additional Lending Installations through which Loans will be made by it and for whose account Loan payments are to be made. A Lender may designate a separate Lending Installation for the purpose of making or maintaining different Types of Loans, and with respect to LIBOR Rate Loans such office may be a domestic or foreign branch or Affiliate of such Lender.

2.16 Non-Receipt of Funds by the Administrative Agent . Unless the Borrower or a Lender, as the case may be, notifies the Administrative Agent prior to the date on which it is scheduled to make payment to the Administrative Agent of (i) in the case of a Lender, the proceeds of a Loan or (ii) in the case of the Borrower, a payment of principal, interest or fees to the Administrative Agent for the account of the Lenders, that it does not intend to make such payment, the Administrative Agent may assume that such payment has been made. The Administrative Agent may, but shall not be obligated to, make the amount of such payment available to the intended Recipient or Recipients in reliance upon such assumption. If such Lender or the Borrower, as the case may be, has not in fact made such payment to the Administrative Agent, the Recipient of such payment shall, on demand by the Administrative Agent, repay to the Administrative Agent the amount so made available together with interest thereon in respect of each day during the period commencing on the date such amount was so made available by the Administrative Agent until the date the Administrative Agent recovers such amount at a rate per annum equal to the Federal Funds Effective Rate for such day for the first three days and, thereafter, at the Alternate Base Rate plus 2%.

2.17 Maximum Interest Rate . Nothing contained in the Loan Documents shall require the Borrower at any time to pay interest at a rate exceeding the Maximum Permissible Rate. If interest payable by the Borrower on any date would exceed the maximum amount permitted by the Maximum Permissible Rate, such interest payment shall automatically be reduced to such maximum permitted amount, and interest for any subsequent period, to the extent less than the maximum amount permitted for such period by the Maximum Permissible Rate, shall be increased by the unpaid amount of such reduction. Any interest actually received for any period in excess of such maximum amount permitted for such period shall be deemed to have been applied as a prepayment of the Loans.

2.18 Increased Costs; Change in Circumstances; Illegality .

2.18.1 Increased Costs Generally . If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit, compulsory loan, insurance charge or similar requirement against assets of, deposits with or for the account of, or credit extended or participated in by, any Lender (except the Reserve Requirement reflected in the LIBOR Rate) or any Issuing Bank;

(ii) subject any Recipient to any Taxes (other than (A) Indemnified Taxes, (B) Taxes described in clauses (ii) through (iv) of the definition of Excluded Taxes and (C) Connection Income Taxes) on its loans, loan principal, letters of credit, commitments, or other obligations, or its deposits, reserves, other liabilities or capital attributable thereto; or

(iii) impose on any Lender or any Issuing Bank or the London interbank market any other condition, cost or expense (other than Taxes) affecting this Agreement or LIBOR Rate Loans or LIBOR Market Index Rate Loans made by such Lender or any Letter of Credit or participation therein;

and the result of any of the foregoing shall be to increase the cost to such Lender, such Issuing Bank or such other Recipient of making, converting to, continuing or maintaining any LIBOR Rate Loan or of maintaining its obligation to make any such Loan, or to increase the cost to such Lender, such Issuing Bank or such other Recipient of participating in, issuing or maintaining any Letter of Credit (or of maintaining its obligation to participate in or to issue any Letter of Credit), or to reduce the amount of any sum received or receivable by such Lender, such Issuing Bank or other Recipient hereunder (whether of principal, interest or any other amount), then, upon request of such Lender, such Issuing Bank or other Recipient, the Borrower will pay to such Lender, such Issuing Bank or other Recipient, as the case may be, such additional amount or amounts as will compensate such Lender, such Issuing Bank or other Recipient, as the case may be, for such additional costs incurred or reduction suffered.

2.18.2 Capital Requirements . If any Lender or any Issuing Bank determines that any Change in Law affecting such Lender or such Issuing Bank or any Lending Installation of such Lender or such Lender's or such Issuing Bank's holding company, if any, regarding capital or liquidity requirements has or would have the effect of reducing the rate of return on such Lender's or such Issuing Bank's capital or on the capital of such Lender's or such Issuing Bank's holding company, if any, as a consequence of this Agreement, the Commitments of such Lender or the Loans made by, or participations in Letters of Credit or Swingline Loans held by, such Lender, or the Letters of Credit issued by such Issuing Bank, to a level below that which such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company could have achieved but for such Change in Law (taking into consideration such Lender's or such Issuing Bank's policies and the policies of such Lender's or such Issuing Bank's holding company with respect to capital adequacy), then from time to time the Borrower will pay to such Lender or such Issuing Bank, as the case may be, such additional amount or amounts as will compensate such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company for any such reduction suffered.

2.18.3 Certificates for Reimbursement . A certificate of a Lender or an Issuing Bank setting forth the amount or amounts necessary to compensate such Lender or such Issuing Bank or its holding company, as the case may be, as specified in Sections 2.18.1 or 2.18.2 and delivered to the Borrower shall be conclusive absent manifest error. The Borrower shall pay such Lender or such Issuing Bank, as the case may be, the amount shown as due on any such certificate within ten days after receipt thereof.

2.18.4 Delay in Requests . Failure or delay on the part of any Lender or any Issuing Bank to demand compensation pursuant to the foregoing provisions of this Section shall not constitute a waiver of such Lender's or such Issuing Bank's right to demand such compensation; provided that the Borrower shall not be required to compensate a Lender or an Issuing Bank pursuant to the foregoing provisions of this Section 2.18 for any increased costs incurred or reductions suffered more than nine months prior to the date that such Lender or such Issuing Bank, as the case may be, notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's or such Issuing Bank's intention to claim compensation therefor (except that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the nine-month period referred to above shall be extended to include the period of retroactive effect thereof).

2.18.5 LIBOR Unavailable . If, (i) on or prior to the first day of any Interest Period, the Administrative Agent shall have determined that adequate and reasonable means do not exist for ascertaining the applicable LIBOR Rate for such Interest Period, (ii) at any time, the Administrative Agent shall have determined that adequate and reasonable means do not exist for ascertaining the applicable LIBOR Market Index Rate, (iii) on or prior to the first day of any Interest Period, the Administrative Agent shall have received written notice from the Required Lenders of their determination that the rate of interest referred to in the definition of “LIBOR Rate” upon the basis of which the LIBOR Rate for LIBOR Rate Loans for such Interest Period is to be determined or will not adequately and fairly reflect the cost to such Lenders of making or maintaining LIBOR Rate Loans during such Interest Period, or (iv) at any time, the Administrative Agent shall have received written notice from the Required Lenders of their determination that the rate of interest referred to in the definition of “LIBOR Market Index Rate” will not adequately and fairly reflect the cost of such Lenders of making LIBOR Market Index Rate Loans, the Administrative Agent will forthwith so notify the Borrower and the Lenders. Upon such notice, (a) all then outstanding LIBOR Rate Loans shall automatically, on the expiration date of the respective Interest Periods applicable thereto (unless then repaid in full), be converted into Base Rate Loans, (b) all then outstanding LIBOR Market Index Rate Loans, shall automatically, on the day of such notice, be converted into Base Rate Loans, (c) the obligation of the Lenders to make, to convert Base Rate Loans into, or to continue, LIBOR Rate Loans shall be suspended (including pursuant to the borrowing to which such Interest Period applies), and (d) any Borrowing Notice, Swingline Borrowing Notice or Conversion/Continuation Notice given at any time thereafter with respect to LIBOR Rate Loans shall be deemed to be a request for Base Rate Loans, in each case until the Administrative Agent or the Required Lenders, as the case may be, shall have determined that the circumstances giving rise to such suspension no longer exist (and the Required Lenders, if making such determination, shall have so notified the Administrative Agent), and the Administrative Agent shall have so notified the Borrower and the Lenders.

2.18.6 Illegality . Notwithstanding any other provision in this Agreement, if, at any time after the date hereof and from time to time, any Lender shall have determined in good faith that the introduction of or any change in any Applicable Law, rule or regulation or in the interpretation or administration thereof by any Governmental Authority charged with the interpretation or administration thereof, or compliance with any guideline or request from any such Governmental Authority (whether or not having the force of law), has or would have the effect of making it unlawful for such Lender to make or to continue to make or maintain LIBOR Rate Loans or LIBOR Market Index Rate Loans, such Lender will forthwith so notify the Administrative Agent and the Borrower. Upon such notice, (i) each of such Lender’s then outstanding LIBOR Rate Loans and LIBOR Market Index Rate Loans shall automatically, immediately in the case of LIBOR Market Index Rate Loans and on the expiration date of the applicable Interest Period in the case of any LIBOR Rate Loan (or, to the extent any such LIBOR Rate Loan may not lawfully be maintained as a LIBOR Rate Loan until such expiration date, upon such notice) and to the extent not sooner prepaid, be converted into a Base Rate Loan, (ii) the obligation of such Lender to make, to convert Base Rate Loans into, or to continue, LIBOR Rate Loans shall be suspended (including pursuant to any borrowing for which the Administrative Agent has received a Borrowing Notice but for which the Borrowing Date has not arrived), and (iii) any Borrowing Notice or Conversion/Continuation Notice given at any time thereafter with respect to LIBOR Rate Loans (or Swingline Borrowing Notice given with respect to any Swingline Loans) shall, as to such Lender, be deemed to be a request for a Base Rate Loan, in each case until such Lender shall have determined that the circumstances giving rise to such suspension no longer exist and shall have so notified the Administrative Agent, and the Administrative Agent shall have so notified the Borrower.

2.19 Taxes .

2.19.1 Issuing Bank . For purposes of this Section 2.19 , the term " Lender " includes any Issuing Bank.

2.19.2 Payments Free of Taxes . Any and all payments by or on account of any obligation of the Borrower under any Loan Document shall be made without deduction or withholding for any Taxes, except as required by Applicable Law. If any Applicable Law (as determined in the good faith discretion of an applicable Withholding Agent) requires the deduction or withholding of any Tax from any such payment by a Withholding Agent, then the applicable Withholding Agent shall be entitled to make such deduction or withholding and shall timely pay the full amount deducted or withheld to the relevant Governmental Authority in accordance with Applicable Law and, if such Tax is an Indemnified Tax, then the sum payable by the Borrower shall be increased as necessary so that after such deduction or withholding has been made (including such deductions and withholdings applicable to additional sums payable under this Section) the applicable Recipient receives an amount equal to the sum it would have received had no such deduction or withholding been made.

2.19.3 Payments of Other Taxes by the Borrower . The Borrower shall timely pay to the relevant Governmental Authority in accordance with Applicable Law, or at the option of the Administrative Agent timely reimburse it for the payment of, any Other Taxes.

2.19.4 Indemnification by the Borrower . The Borrower shall indemnify each Recipient, within 10 days after demand therefor, for the full amount of any Indemnified Taxes (including Indemnified Taxes imposed or asserted on or attributable to amounts payable under this Section 2.19) payable or paid by such Recipient or required to be withheld or deducted from a payment to such Recipient and any reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to the Borrower by a Lender (with a copy to the Administrative Agent), or by the Administrative Agent on its own behalf or on behalf of a Lender, shall be conclusive absent manifest error.

2.19.5 Indemnification by the Lenders . Each Lender shall severally indemnify the Administrative Agent, within 10 days after demand therefor, for (i) any Indemnified Taxes attributable to such Lender (but only to the extent that the Borrower has not already indemnified the Administrative Agent for such Indemnified Taxes and without limiting the obligation of the Borrower to do so), (ii) any Taxes attributable to such Lender's failure to comply with the provisions of Section 12.2 relating to the maintenance of a Participant Register and (iii) any Excluded Taxes attributable to such Lender, in each case, that are payable or paid by the Administrative Agent in connection with any Loan Document, and any reasonable expenses arising therefrom or with respect thereto, whether or not such Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to any Lender by the Administrative Agent shall be conclusive absent manifest error. Each Lender hereby authorizes the Administrative Agent to set off and apply any and all amounts at any time owing to such Lender under any Loan Document or otherwise payable by the Administrative Agent to the Lender from any other source against any amount due to the Administrative Agent under this Section 2.19.5 .

2.19.6 Evidence of Payments . As soon as practicable after any payment of Taxes by the Borrower to a Governmental Authority pursuant to this Section 2.19 , the Borrower shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

2.19.7 Status of Lenders .

(i) Any Lender that is entitled to an exemption from or reduction of withholding Tax with respect to payments made under any Loan Document shall deliver to the Borrower and the Administrative Agent, at the time or times reasonably requested by the Borrower or the Administrative Agent, such properly completed and executed documentation reasonably requested by the Borrower or the Administrative Agent as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, any Lender, if reasonably requested by the Borrower or the Administrative Agent, shall deliver such other documentation prescribed by Applicable Law or reasonably requested by the Borrower or the Administrative Agent as will enable the Borrower or the Administrative Agent to determine whether or not such Lender is subject to backup withholding or information reporting requirements. Notwithstanding anything to the contrary in the preceding two sentences, the completion, execution and submission of such documentation (other than such documentation set forth in clauses (ii)(a), (ii)(b) and (ii)(d) below) shall not be required if in the Lender's reasonable judgment such completion, execution or submission would subject such Lender to any material unreimbursed cost or expense or would materially prejudice the legal or commercial position of such Lender.

(ii) Without limiting the generality of the foregoing, in the event that the Borrower is a U.S. Borrower,

(a) any Lender that is a U.S. Person shall deliver to the Borrower and the Administrative Agent on or prior to the date on which such Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed originals of IRS Form W-9 certifying that such Lender is exempt from U.S. federal backup withholding tax;

(b) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), whichever of the following is applicable:

(1) in the case of a Foreign Lender claiming the benefits of an income tax treaty to which the United States is a party (x) with respect to payments of interest under any Loan Document, executed originals of IRS Form W-8BEN establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "interest" article of such tax treaty and (y) with respect to any other applicable payments under any Loan Document, IRS Form W-8BEN establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "business profits" or "other income" article of such tax treaty;

(2) executed originals of IRS Form W-8ECI;

(3) in the case of a Foreign Lender claiming the benefits of the exemption for portfolio interest under Section 881(c) of the Code, (x) a certificate substantially in the form of Exhibit 2.19-A to the effect that such Foreign Lender is not a "bank" within the meaning of Section 881(c)(3)(A) of the Code, a "10 percent shareholder" of the Borrower within the meaning of Section 881(c)(3)(B) of the Code, or a "controlled foreign corporation" described in Section 881(c)(3)(C) of the Code (a " U.S. Tax Compliance Certificate ") and (y) executed originals of IRS Form W-8BEN; or

(4) to the extent a Foreign Lender is not the beneficial owner, executed originals of IRS Form W-8IMY, accompanied by IRS Form W-8ECI, IRS Form W-8BEN, a U.S. Tax Compliance Certificate substantially in the form of Exhibit 2.19-B or Exhibit 2.19-C , IRS Form W-9, and/or other certification documents from each beneficial owner, as applicable; provided that if the Foreign Lender is a partnership and one or more direct or indirect partners of such Foreign Lender are claiming the portfolio interest exemption, such Foreign Lender may provide a U.S. Tax Compliance Certificate substantially in the form of Exhibit 2.19-D on behalf of each such direct and indirect partner;

(c) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed originals of any other form prescribed by Applicable Law as a basis for claiming exemption from or a reduction in U.S. federal withholding Tax, duly completed, together with such supplementary documentation as may be prescribed by Applicable Law to permit the Borrower or the Administrative Agent to determine the withholding or deduction required to be made; and

(d) if a payment made to a Lender under any Loan Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Lender were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Lender shall deliver to the Borrower and the Administrative Agent at the time or times prescribed by law and at such time or times reasonably requested by the Borrower or the Administrative Agent such documentation prescribed by Applicable Law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by the Borrower or the Administrative Agent as may be necessary for the Borrower and the Administrative Agent to comply with their obligations under FATCA and to determine that such Lender has complied with such Lender's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this clause (D), "FATCA" shall include any amendments made to FATCA after the date of this Agreement.

Each Lender agrees that if any form or certification it previously delivered expires or becomes obsolete or inaccurate in any respect, it shall update such form or certification or promptly notify the Borrower and the Administrative Agent in writing of its legal inability to do so.

2.19.8 Treatment of Certain Refunds . If any party determines, in its sole discretion exercised in good faith, that it has received a refund of any Taxes as to which it has been indemnified pursuant to this Section 2.19 (including by the payment of additional amounts pursuant to this Section 2.19), it shall pay to the indemnifying party an amount equal to such refund (but only to the extent of indemnity payments made under this Section with respect to the Taxes giving rise to such refund), net of all out-of-pocket expenses (including Taxes) of such indemnified party and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund). Such indemnifying party, upon the request of such indemnified party, shall repay to such indemnified party the amount paid over pursuant to this Section 2.19.8 (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) in the event that such indemnified party is required to repay such refund to such Governmental Authority. Notwithstanding anything to the contrary in this Section 2.19.8 , in no event will the indemnified party be required to pay any amount to an indemnifying party pursuant to this Section 2.19.8 the payment of which would place the indemnified party in a less favorable net after-Tax position than the indemnified party would have been in if the indemnification payments or additional amounts giving rise to such refund had never been paid. This paragraph shall not be construed to require any indemnified party to make available its Tax returns (or any other information relating to its Taxes that it deems confidential) to the indemnifying party or any other Person.

2.19.9 Survival . Each party's obligations under this Section 2.19 shall survive the resignation or replacement of the Administrative Agent or any assignment of rights by, or the replacement of, a Lender, the termination of the Commitments and the repayment, satisfaction or discharge of all obligations under any Loan Document.

2.20 Compensation . The Borrower will compensate each Lender upon demand for all losses, expenses and liabilities (including, without limitation, any loss, expense or liability incurred by reason of the liquidation or reemployment of deposits or other funds required by such Lender to fund or maintain LIBOR Rate Loans) that such Lender may incur or sustain (i) if for any reason (other than a default by such Lender) a borrowing or continuation of, or conversion into, a LIBOR Rate Loan does not occur on a date specified therefor in a Borrowing Notice or Conversion/Continuation Notice, (ii) if any repayment, prepayment or conversion of any LIBOR Rate Loan occurs on a date other than the last day of an Interest Period applicable thereto (including as a consequence of any assignment made pursuant to Section 2.21.1 or any acceleration of the maturity of the Loans pursuant to ARTICLE VIII) , (iii) if any prepayment of any LIBOR Rate Loan is not made on any date specified in a notice of prepayment given by the Borrower or (iv) as a consequence of any other failure by the Borrower to make any payments with respect to any LIBOR Rate Loan when due hereunder. Calculation of all amounts payable to a Lender under this Section 2.20 shall be made as though such Lender had actually funded its relevant LIBOR Rate Loan through the purchase of a eurodollar deposit bearing interest at the LIBOR Rate in an amount equal to the amount of such LIBOR Rate Loan, having a maturity comparable to the relevant Interest Period; provided , however , that each Lender may fund its LIBOR Rate Loans in any manner it sees fit and the foregoing assumption shall be utilized only for the calculation of amounts payable under this Section 2.20 . A certificate (which shall be in reasonable detail) showing the bases for the determinations set forth in this Section 2.20 by any Lender as to any additional amounts payable pursuant to this Section 2.20 shall be submitted by such Lender to the Borrower either directly or through the Administrative Agent. Determinations set forth in any such certificate made in good faith for purposes of this Section 2.20 of any such losses, expenses or liabilities shall be conclusive absent manifest error.

2.21 Mitigation Obligations; Replacement of Lenders .

2.21.1 If any Lender requests compensation under Section 2.18 , or requires the Borrower to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.19 , then such Lender shall (at the request of the Borrower) use reasonable efforts to designate a different Lending Installation for funding or booking its Loans hereunder or to assign its rights and obligations hereunder to another of its offices, branches or affiliates, if, in the judgment of such Lender, such designation or assignment (i) would eliminate or reduce amounts payable pursuant to Sections 2.18 or 2.19 , as the case may be, in the future, and (ii) would not subject such Lender to any unreimbursed cost or expense and would not otherwise be disadvantageous to such Lender. The Borrower hereby agrees to pay all reasonable costs and expenses incurred by any Lender in connection with any such designation or assignment.

2.21.2 If any Lender requests compensation under Section 2.18 , or if the Borrower is required to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant Section 2.19 and, in each case, such Lender has declined or is unable to designate a different Lending Installation in accordance with Section 2.21.1 , or if any Lender is a Defaulting Lender or a Non-Consenting Lender, then the Borrower may, at its sole expense and effort, upon notice to such Lender and the Administrative Agent, require such Lender to assign and delegate, without recourse (in accordance with and subject to the restrictions contained in, and consents required by, Section 12.3), all of its interests, rights (other than its existing rights to payments pursuant to Section 2.18 or 2.19) and obligations under this Agreement and the related Loan Documents to an Eligible Assignee that shall assume such obligations (which assignee may be another Lender, if a Lender accepts such assignment); provided that :

(i) the Borrower shall have paid to the Administrative Agent the assignment fee (if any) specified in Section 12.3.2 ;

(ii) such Lender shall have received payment of an amount equal to the outstanding principal of its Loans and any funded participations in Letters of Credit not refinanced through the Borrowing of Revolving Loans, accrued interest thereon, accrued fees and all other amounts payable to it hereunder and under the other Loan Documents (including any amounts under Section 2.20) from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Borrower (in the case of all other amounts);

(iii) in the case of any such assignment resulting from a request for compensation under Section 2.18 or payments required to be made pursuant to Section 2.19 , such assignment will result in a reduction in such compensation or payments thereafter;

(iv) such assignment does not conflict with Applicable Law; and

(v) in the case of any assignment resulting from a Lender becoming a Non-Consenting Lender, the applicable assignee shall have consented to the applicable amendment, waiver or consent.

A Lender shall not be required to make any such assignment or delegation if, prior thereto, as a result of a waiver by such Lender or otherwise, the circumstances entitling the Borrower to require such assignment and delegation cease to apply.

2.22 Defaulting Lenders .

2.22.1 Defaulting Lender Adjustments . Notwithstanding anything to the contrary contained in this Agreement, if any Lender becomes a Defaulting Lender, then, until such time as such Lender is no longer a Defaulting Lender, to the extent permitted by Applicable Law:

(i) Waivers and Amendments . Such Defaulting Lender's right to approve or disapprove any amendment, waiver or consent with respect to this Agreement shall be restricted as set forth in the definition of "Required Lenders" and in Section 8.2 .

(ii) Defaulting Lender Waterfall . Any payment of principal, interest, fees or other amounts received by the Administrative Agent for the account of such Defaulting Lender (whether voluntary or mandatory, at maturity, pursuant to or ARTICLE VII otherwise) or received by the Administrative Agent from a Defaulting Lender pursuant to ARTICLE XI shall be applied at such time or times as may be determined by the Administrative Agent as follows:

(a) first , to the payment of any amounts owing by such Defaulting Lender to the Administrative Agent hereunder;

(b) second , to the payment on a pro rata basis of any amounts owing by such Defaulting Lender to any Issuing Bank or the Swingline Lender hereunder;

(c) third , if so determined by the Administrative Agent or requested by any Issuing Bank or the Swingline Lender, to be held as Cash Collateral for future funding obligations of such Defaulting Lender in respect of any participation in any Letter of Credit or Swingline Loan;

(d) fourth, as the Borrower may request (so long as no Unmatured Default or Event of Default exists), to the funding of any Loan in respect of which such Defaulting Lender has failed to fund its portion thereof as required by this Agreement, as determined by the Administrative Agent;

(e) fifth, if so determined by the Administrative Agent and the Borrower, to be held in a non-interest bearing deposit account and released in order to satisfy obligations of such Defaulting Lender to fund Loans under this Agreement;

(f) sixth, to the payment of any amounts owing to the Lenders, the Issuing Banks or the Swingline Lender as a result of any judgment of a court of competent jurisdiction obtained by any Lender, any Issuing Bank or the Swingline Lender against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement;

(g) seventh, so long as no Unmatured Default or Event of Default exists, to the payment of any amounts owing to the Borrower as a result of any judgment of a court of competent jurisdiction obtained by the Borrower against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement; and

(h) eighth, to such Defaulting Lender or as otherwise directed by a court of competent jurisdiction;

provided that if (x) such payment is a payment of the principal amount of any Loans or any Letter of Credit Exposure in respect of which such Defaulting Lender has not fully funded its appropriate share, and (y) such Loans were made or the related Letters of Credit were issued at a time when the conditions set forth in Section 4.2 were satisfied or waived, such payment shall be applied solely to pay the Loans of, and obligations in respect of Letters of Credit owed to, all non-Defaulting Lenders on a pro rata basis prior to being applied to the payment of any Loans of, or obligations in respect of Letters of Credit owed to, such Defaulting Lender. Any payments, prepayments or other amounts paid or payable to a Defaulting Lender that are applied (or held) to pay amounts owed by a Defaulting Lender or to post Cash Collateral pursuant to this Section 2.22.1(ii) shall be deemed paid to and redirected by such Defaulting Lender, and each Lender irrevocably consents hereto.

(iii) Any Defaulting Lender shall be entitled to receive any Facility Fee for any period during which such Lender is a Defaulting Lender only to the extent allocable to the sum of (1) the outstanding amount of the Revolving Loans funded by it and (2) its Letter of Credit Exposure and Swingline Exposure for which it has provided Cash Collateral pursuant to Section 2.22.3 (and the Borrower shall (A) be required to pay the applicable Issuing Bank and the Swingline Lender the amount of such fee allocable to its Fronting Exposure arising from such Defaulting Lender and (B) not be required to pay the remaining amount of such fee that otherwise would have been required to have been paid to such Defaulting Lender).

(iv) All or any part of such Defaulting Lender's Letter of Credit Exposure and Swingline Exposure shall automatically (effective on the day such Lender becomes a Defaulting Lender) be reallocated among the non-Defaulting Lenders in accordance with their respective

Applicable Percentages (calculated without regard to such Defaulting Lender's Commitment) but only to the extent that (x) no Unmatured Default or Event of Default shall have occurred and be continuing (and, unless the Borrower shall have otherwise notified the Administrative Agent at the time, the Borrower shall be deemed to have represented and warranted that such condition is satisfied at such time) and (y) such reallocation does not cause the Credit Exposure of any non-Defaulting Lender to exceed such non-Defaulting Lender's Commitment.

(v) If the reallocation described in Section 2.22.1(iv) cannot, or can only partially, be effected, the Borrower shall, without prejudice to any right or remedy available to it hereunder or under law, within one Business Day following notice by the Administrative Agent, (x) first , prepay Swingline Loans in an amount equal to the Swingline Lenders' Fronting Exposure and (y) second , Cash Collateralize each Issuing Banks' Fronting Exposure in accordance with the procedures set forth in Section 2.22.3 .

2.22.2 If the Borrower, the Administrative Agent, the Issuing Banks and the Swingline Lender agree in writing in their sole discretion that a Defaulting Lender should no longer be deemed to be a Defaulting Lender, the Administrative Agent will so notify the parties hereto, whereupon as of the effective date specified in such notice and subject to any conditions set forth therein (which may include arrangements with respect to any Cash Collateral), such Lender will, to the extent applicable, purchase that portion of outstanding Loans of the other Lenders or take such other actions as the Administrative Agent may determine to be necessary to cause the Revolving Loans and funded and unfunded participations in Letters of Credit and Swingline Loans to be held by the Lenders in accordance with their respective Applicable Percentages (without giving effect to Section 2.22.1(iv)), whereupon such Lender will cease to be a Defaulting Lender; provided that no adjustments will be made retroactively with respect to fees accrued or payments made by or on behalf of the Borrower while such Lender was a Defaulting Lender; provided further that, except to the extent otherwise expressly agreed by the affected parties, no change hereunder from Defaulting Lender to Lender will constitute a waiver or release of any claim of any party hereunder arising from such Lender's having been a Defaulting Lender.

2.22.3 At any time that there shall exist a Defaulting Lender, within one Business Day upon the request of the Administrative Agent, any Issuing Bank or the Swingline Lender, the Borrower shall deliver to the Administrative Agent Cash Collateral in an amount sufficient to cover all Fronting Exposure (after giving effect to Section 2.22.1(iv) and any Cash Collateral provided by the Defaulting Lender).

(i) All Cash Collateral (other than credit support not constituting funds subject to deposit) shall be maintained in blocked, non-interest bearing deposit accounts with the Administrative Agent. The Borrower, and to the extent provided by any Lender, such Lender, hereby grants to (and subjects to the control of) the Administrative Agent, for the benefit of the Administrative Agent, the Issuing Bank and the Lenders (including the Swingline Lender), and agrees to maintain, a first priority security interest in all such cash, deposit accounts and all balances therein, and all other property so provided as collateral pursuant hereto, and in all proceeds of the foregoing, all as security for the obligations to which such Cash Collateral may be applied pursuant to Section 2.22.3(ii) . If at any time the Administrative Agent determines that Cash Collateral is subject to any right or claim of any Person other than the Administrative

Agent as herein provided, or that the total amount of such Cash Collateral is less than the applicable Fronting Exposure and other obligations secured thereby, the Borrower or the relevant Defaulting Lender will, promptly upon demand by the Administrative Agent, pay or provide to the Administrative Agent additional Cash Collateral in an amount sufficient to eliminate such deficiency.

(ii) Notwithstanding anything to the contrary contained in this Agreement, Cash Collateral provided under this Section 2.22 in respect of Letters of Credit shall be held and applied to the satisfaction of the specific Letter of Credit Exposure, obligations to fund participations therein (including, as to Cash Collateral provided by a Defaulting Lender, any interest accrued on such obligation) and other obligations for which the Cash Collateral was so provided, prior to any other application of such Cash Collateral as may be provided for herein.

(iii) Cash Collateral (or the appropriate portion thereof) provided to reduce any Issuing Bank's Fronting Exposure shall no longer be required to be held as Cash Collateral pursuant to this Section following (A) the elimination of the applicable Fronting Exposure (including by the termination of Defaulting Lender status of the applicable Lender), or (B) the determination by the Administrative Agent and each Issuing Bank that there exists excess Cash Collateral; provided that, subject to this Section 2.22 the Person providing Cash Collateral and each Issuing Bank may agree that Cash Collateral shall be held to support future anticipated Fronting Exposure or other obligations and provided further that to the extent that such Cash Collateral was provided by the Borrower, such Cash Collateral shall remain subject to the security interest granted pursuant to the Loan Documents.

2.22.4 So long as any Lender is a Defaulting Lender, (i) the Swingline Lender shall not be required to fund any Swingline Loans unless it is satisfied that it will have no Fronting Exposure after giving effect to such Swingline Loan and (ii) no Issuing Bank shall be required to issue, extend, renew or increase any Letter of Credit unless it is satisfied that it will have no Fronting Exposure after giving effect thereto.

ARTICLE III

LETTERS OF CREDIT

3.1 Issuance . Subject to and upon the terms and conditions herein set forth, so long as no Unmatured Default or Event of Default has occurred and is continuing, each Issuing Bank will, at any time and from time to time on and after the Agreement Date and prior to the earlier of (i) the Letter of Credit Maturity Date and (ii) the Repayment Date, and upon request by the Borrower in accordance with the provisions of Section 3.1 , issue for the account of the Borrower one or more irrevocable standby letters of credit denominated in Dollars and in a form customarily used or otherwise approved by such Issuing Bank (together with all amendments, modifications and supplements thereto, substitutions therefor and renewals and restatements thereof, collectively, the " Letters of Credit "). The Stated Amount of each Letter of Credit shall not be less than such amount as may be acceptable to the applicable Issuing Bank. Notwithstanding the foregoing:

3.1.1 No Letter of Credit shall be issued if, after giving effect to such issuance, (i) the Stated Amount when added to the aggregate Letter of Credit Exposure of the Lenders at such time, would exceed the Letter of Credit Subcommitment, (ii) the Stated Amount when added to the aggregate outstanding Credit Exposure, would exceed the Aggregate Commitments at such time, and (iii) any Lender is at that time a Defaulting Lender, unless the applicable Issuing Bank has entered into an arrangement, including the delivery of Cash Collateral, satisfactory to such Issuing Bank (in its sole discretion) with the Borrower or such Lender to eliminate such Issuing Bank's actual or potential Fronting Exposure (after giving effect to Section 2.22.1(iv)) with respect to the Defaulting Lender arising from either the Letter of Credit then proposed to be issued or that Letter of Credit and all other Letter of Credit Exposure as to which such Issuing Bank has actual or potential Fronting Exposure, as it may elect in its sole discretion;

3.1.2 No Letter of Credit shall be issued that by its terms expires later than the Letter of Credit Maturity Date or, in any event, more than one year after its date of issuance; provided , however , that a Letter of Credit may, if requested by the Borrower, provide by its terms, and on terms acceptable to the applicable Issuing Bank, for renewal for successive periods of one year or less (but not beyond the Letter of Credit Maturity Date), unless and until the applicable Issuing Bank shall have delivered a notice of nonrenewal to the beneficiary of such Letter of Credit;

3.1.3 No Issuing Bank shall be under any obligation to issue any Letter of Credit if, at the time of such proposed issuance, (i) any order, judgment or decree of any Governmental Authority or arbitrator shall purport by its terms to enjoin or restrain such Issuing Bank from issuing such Letter of Credit, or any Applicable Law or any request or directive (whether or not having the force of law) from any Governmental Authority with jurisdiction over such Issuing Bank shall prohibit, or request that such Issuing Bank refrain from, the issuance of letters of credit generally or such Letter of Credit in particular or shall impose upon such Issuing Bank with respect to such Letter of Credit any restriction or reserve or capital requirement (for which such Issuing Bank is not otherwise compensated) not in effect on the Agreement Date, or any unreimbursed loss, cost or expense that was not applicable, in effect or known to such Issuing Bank as of the Agreement Date and that the Issuing Bank in good faith deems material to it, (ii) such Issuing Bank shall have actual knowledge, or shall have received notice from any Lender, prior to the issuance of such Letter of Credit that one or more of the conditions specified in Section 4.1 (if applicable) or Section 4.2 are not then satisfied (or have not been waived in writing as required herein) or that the issuance of such Letter of Credit would violate the provisions of Section 3.1.1 , or (iii) the issuance of such Letter of Credit would violate one or more written policies of such Issuing Bank applicable to letters of credit generally; and

3.1.4 Unless otherwise expressly agreed by the applicable Issuing Bank and the Borrower when a Letter of Credit is issued and subject to applicable laws, performance under Letters of Credit by the applicable Issuing Bank, its correspondents, and the beneficiaries thereof will be governed by the rules of the "International Standby Practices 1998" (or such later revision as may be published by the Institute of International Banking Law & Practice on any date any Letter of Credit may be issued) and to the extent not inconsistent therewith, the governing law of this Agreement.

3.2 Notices. Whenever the Borrower desires the issuance of a Letter of Credit, the Borrower will give the applicable Issuing Bank written notice with a copy to the Administrative Agent not later than 11:00 a.m. three Business Days (or such shorter period as is acceptable to the Issuing Bank in any given case) prior to the requested date of issuance thereof. Each such notice (each, a " Letter of Credit Notice ") shall be irrevocable, shall be given in the form of Exhibit 3.2 and shall specify (i) the requested date of issuance, which shall be a Business Day, (ii) the requested Stated Amount and expiry date of the Letter of Credit, and (iii) the name and address of the requested beneficiary or beneficiaries of the Letter of Credit. The Borrower will also complete any application procedures and documents reasonably required by the applicable Issuing Bank in connection with the issuance of any Letter of Credit. Upon its issuance of any Letter of Credit, the applicable Issuing Bank will promptly notify the Administrative Agent of such issuance, and the Administrative Agent will give prompt notice thereof to each Lender. The renewal or extension of any outstanding Letter of Credit shall, for purposes of this Article III, be treated in all respects as the issuance of a new Letter of Credit.

3.3 Participations. Immediately upon the issuance of any Letter of Credit, the Issuing Bank shall be deemed to have sold and transferred to each Lender, and each Lender shall be deemed irrevocably and unconditionally to have purchased and received from the Issuing Bank, without recourse or warranty, an undivided interest and participation, of its Applicable Percentage of such Letter of Credit, each drawing made thereunder and the obligations of the Borrower under this Agreement with respect thereto and any Collateral or other security therefor or guaranty pertaining thereto; provided, however, that the LC Fee shall be payable directly to the Issuing Bank as provided therein, and the other Lenders shall have no right to receive any portion thereof. In consideration and in furtherance of the foregoing, each Lender hereby absolutely and unconditionally agrees to pay to the Administrative Agent, for the account of the Issuing Bank, such Lender's Applicable Percentage of each Reimbursement Obligation not reimbursed by the Borrower on the date due as provided in Section 3.4 or through the Borrowing of Revolving Loans as provided in Section 3.5 (because the conditions set forth in Section 4.2 cannot be satisfied, or for any other reason), or of any reimbursement payment required to be refunded to the Borrower for any reason. Upon any change in the Commitments of any of the Lenders pursuant to Section 2.5.2 or Section 12.3, with respect to all outstanding Letters of Credit and Reimbursement Obligations there shall be an automatic adjustment to the participations pursuant to this Section 3.3 to reflect the new Applicable Percentages of the assigning Lender and the assignee. Each Lender's obligation to make payment to the Issuing Banks pursuant to this Section 3.3 shall be absolute and unconditional and shall not be affected by any circumstance whatsoever, including the termination of the Commitments or the existence of any Unmatured Default or Event of Default, and each such payment shall be made without any offset, abatement, reduction or withholding whatsoever.

3.4 Reimbursement. The Borrower hereby agrees to reimburse the applicable Issuing Bank by making payment to the Administrative Agent, for the account of such Issuing Bank, in immediately available funds, for any payment made by such Issuing Bank under any Letter of Credit issued by it (each such amount so paid until reimbursed, together with interest thereon payable as provided hereinbelow, a " Reimbursement Obligation ") immediately upon, and in any event on the same Business Day as, the making of such payment by such Issuing Bank (the " Honor Date "), provided that any such Reimbursement Obligation shall be deemed timely satisfied (but nevertheless subject to the payment of interest thereon as provided herein below) if satisfied pursuant to a borrowing of Revolving Loans made on the date of such payment by the Issuing Bank, as set forth more completely in Section 3.5), together with interest on the amount so paid by such Issuing Bank, to the extent not reimbursed prior to 2:00 p.m. on the Honor Date, for the period from the Honor Date to the date the Reimbursement Obligation created thereby is satisfied, at the Alternate Base Rate plus the Applicable Margin plus 2% per annum as in effect from time to time during such period, such interest also to be payable on demand. Each Issuing Bank will provide the Administrative Agent and the Borrower with prompt notice of any payment or disbursement made or to be made under any Letter of Credit issued by it, although the failure to give, or any delay in giving, any such notice shall not release, diminish or otherwise affect the Borrower's obligations under this Section 3.4 or any other provision of this Agreement. The Administrative Agent will promptly pay to the applicable Issuing Bank any such amounts received by it under this Section 3.4 .

3.5 Payment by Revolving Loans .

3.5.1 In the event that any Issuing Bank makes any payment under any Letter of Credit and the Borrower shall not have timely satisfied in full its Reimbursement Obligation to such Issuing Bank pursuant to Section 3.4 , the Borrower shall be deemed to have requested a Borrowing of Base Rate Loans to be disbursed on the Honor Date in an amount equal to the Reimbursement Obligation (the " Unreimbursed Amount "), without regard to the minimum and multiples for the principal amount of Base Rate Loans, but subject to the amount of the unutilized portion of the Aggregate Commitments and the conditions set forth in Section 4.2 (other than the delivery of a Notice of Borrowing). Any notice given by the applicable Issuing Bank or the Administrative Agent pursuant to this Section 3.5.1 may be given by telephone if immediately confirmed in writing; provided that the lack of such an immediate confirmation shall not affect the conclusiveness or binding effect of such notice.

3.5.2 Each Lender shall upon any notice pursuant to Section 3.5.1 make funds available (and the Administrative Agent may apply Cash Collateral provided for this purpose) for the account of the applicable Issuing Bank in an amount equal to its Applicable Percentage of the Unreimbursed Amount not later than 1:00 p.m. on the Business Day specified in such notice by the Administrative Agent, whereupon, subject to the provisions of Section 3.5.3 , each Lender that so makes funds available shall be deemed to have made a Base Rate Loan to the Borrower in such amount. The Administrative Agent shall remit the funds so received to the applicable Issuing Bank.

3.5.3 With respect to any Unreimbursed Amount that is not fully refinanced by a borrowing of Base Rate Loans because the conditions set forth in Section 4.2 cannot be satisfied or for any other reason, each Lender shall fund its risk participation in such Letter of Credit in the amount of its Applicable Percentage of the Unreimbursed Amount that is not so refinanced, which funded risk participation shall be due and payable on demand (together with interest) and shall bear interest at the Overdue Rate.

3.5.4 Until each Lender funds its Base Rate Loan or risk participation pursuant to this Section 3.5 to reimburse the applicable Issuing Bank for any amount drawn under any Letter of Credit, interest in respect of such Lender's Applicable Percentage of such amount shall be solely for the account of the applicable Issuing Bank.

3.5.5 Each Lender's obligation to make Base Rate Loans or to fund its risk participation to reimburse the applicable Issuing Bank for amounts drawn under Letters of Credit, as contemplated by this Section 3.5 , shall be absolute and unconditional and shall not be affected by any circumstance, including (A) any setoff, counterclaim, recoupment, defense or other right which such Lender may have against such Issuing Bank, the Borrower or any other Person for any reason whatsoever; (B) the occurrence or continuance of an Unmatured Default or Event of Default, or (C) any other occurrence, event or condition, whether or not similar to any of the foregoing; provided , however , that each Lender's obligation to make Base Rate Loans pursuant to this Section 3.5 is subject to the conditions set forth in Section 4.2 (other than delivery by the Borrower of a Notice of Borrowing). No such making of a Base Rate Loan or funding of risk participation shall relieve or otherwise impair the obligation of the Borrower to reimburse the applicable Issuing Bank for the amount of any payment made by such Issuing Bank under any Letter of Credit, together with interest as provided herein.

3.5.6 If any Lender fails to make available to the Administrative Agent for the account of the applicable Issuing Bank any amount required to be paid by such Lender pursuant to the foregoing provisions of this Section 3.5 by the time specified in Section 3.5.2 , then, without limiting the other provisions of this Agreement, the applicable Issuing Bank shall be entitled to recover from such Lender (acting through the Administrative Agent), on demand, such amount with interest thereon for the period from the date such payment is required to the date on which such payment is immediately available to such Issuing Bank at a rate per annum equal to the greater of the Federal Funds Rate and a rate determined by such Issuing Bank in accordance with banking industry rules on interbank compensation, plus any administrative, processing or similar fees customarily charged by such Issuing Bank in connection with the foregoing. If such Lender pays such amount (with interest and fees as aforesaid), the amount so paid shall constitute such Lender's Base Rate Loan included in the relevant borrowing or funded risk participation, as the case may be. A certificate of the applicable Issuing Bank submitted to any Lender (through the Administrative Agent) with respect to any amounts owing under this Section 3.5.6 shall be conclusive absent manifest error.

3.6 Payment to Lenders . Whenever any Issuing Bank receives a payment in respect of a Reimbursement Obligation as to which the Administrative Agent has received, for the account of such Issuing Bank, any payments from the Lenders pursuant to Section 3.5 , such Issuing Bank will promptly pay to the Administrative Agent, and the Administrative Agent will promptly pay to each Lender that has paid its ratable share thereof, in immediately available funds, an amount equal to such Lender's ratable share (based on the proportionate amount funded by such Lender to the aggregate amount funded by all Lenders) of such Reimbursement Obligation.

3.7 Obligations Absolute . The Reimbursement Obligations of the Borrower shall be irrevocable, shall remain in effect until the Issuing Banks shall have no further obligations to make any payments or disbursements under any circumstances with respect to any Letter of Credit, and shall be absolute and unconditional, shall not be subject to counterclaim, setoff or other defense or any other qualification or exception whatsoever and shall be made in accordance with the terms and conditions of this Agreement under all circumstances, including, without limitation, any of the following circumstances:

3.7.1 Any lack of validity or enforceability of this Agreement, any of the other Loan Documents or any documents or instruments relating to any Letter of Credit;

3.7.2 Any change in the time, manner or place of payment of, or in any other term of, all or any of the Obligations in respect of any Letter of Credit or any other amendment, modification or waiver of or any consent to departure from any Letter of Credit or any documents or instruments relating thereto, in each case whether or not the Borrower has notice or knowledge thereof;

3.7.3 The existence of any claim, setoff, defense or other right that the Borrower may have at any time against a beneficiary named in a Letter of Credit, any transferee of any Letter of Credit (or any Person for whom any such transferee may be acting), the Administrative Agent, any Issuing Bank, any Lender or other Person, whether in connection with this Agreement, any Letter of Credit, the transactions contemplated hereby or any unrelated transactions (including any underlying transaction between the Borrower and the beneficiary named in any such Letter of Credit);

3.7.4 Any draft, certificate or any other document presented under the Letter of Credit proving to be forged, fraudulent, invalid or insufficient in any respect or any statement therein being untrue or inaccurate in any respect (provided that such draft, certificate or other document appears on its face to comply with the terms of such Letter of Credit), any errors, omissions, interruptions or delays in transmission or delivery of any messages, by mail, facsimile or otherwise, or any errors in translation or in interpretation of technical terms;

3.7.5 Any defense based upon the failure of any drawing under a Letter of Credit to conform to the terms of the Letter of Credit (provided that any draft, certificate or other document presented pursuant to such Letter of Credit appears on its face to comply with the terms thereof), any nonapplication or misapplication by the beneficiary or any transferee of the proceeds of such drawing or any other act or omission of such beneficiary or transferee in connection with such Letter of Credit;

3.7.6 The exchange, release, surrender or impairment of any collateral or other security for the Obligations;

3.7.7 The occurrence of any Unmatured Default or Event of Default; or

3.7.8 Any other circumstance or event whatsoever, including, without limitation, any other circumstance that might otherwise constitute a defense available to, or a discharge of, the Borrower or a guarantor.

Any action taken or omitted to be taken by any Issuing Bank under or in connection with any Letter of Credit, if taken or omitted in the absence of gross negligence or willful misconduct, shall be binding upon the Borrower and each Lender and shall not create or result in any liability of such Issuing Bank to the Borrower or any Lender. It is expressly understood and agreed that, for purposes of determining whether a wrongful payment under a Letter of Credit resulted from any Issuing Bank's gross negligence or willful misconduct, (i) such Issuing Bank's acceptance of documents that appear on their face to comply with the terms of such Letter of Credit, without responsibility for further investigation, regardless of any notice or information to the contrary,

(ii) such Issuing Bank's exclusive reliance on the documents presented to it under such Letter of Credit as to any and all matters set forth therein, including the amount of any draft presented under such Letter of Credit, whether or not the amount due to the beneficiary thereunder equals the amount of such draft and whether or not any document presented pursuant to such Letter of Credit proves to be insufficient in any respect (so long as such document appears on its face to comply with the terms of such Letter of Credit), and whether or not any other statement or any other document presented pursuant to such Letter of Credit proves to be forged or invalid or any statement therein proves to be inaccurate or untrue in any respect whatsoever, and (iii) any noncompliance in any immaterial respect of the documents presented under such Letter of Credit with the terms thereof shall, in each case, be deemed not to constitute gross negligence or willful misconduct of such Issuing Bank.

3.8 Cash Collateral Account . At any time and from time to time (i) after the occurrence and during the continuance of an Event of Default, the Administrative Agent may, and at the direction or with the consent of the Required Lenders shall, require the Borrower to deliver to the Administrative Agent such additional amount of cash as is equal to 102% of the aggregate Stated Amount of all Letters of Credit at any time outstanding (whether or not any beneficiary under any Letter of Credit shall have drawn or be entitled at such time to draw thereunder) and (ii) in the event of a prepayment under Section 2.5.1 , the Administrative Agent will retain such amount as may then be required to be retained, such amounts in each case under clauses (i) and (ii) above to be held by the Administrative Agent in a cash collateral account (the " Cash Collateral Account "). The Borrower hereby grants to the Administrative Agent, for the benefit of the Issuing Bank and the Lenders, a Lien upon and security interest in the Cash Collateral Account and all amounts held therein from time to time as security for Letter of Credit Exposure, and for application to the Borrower's Reimbursement Obligations as and when the same shall arise. The Administrative Agent shall have exclusive dominion and control, including the exclusive right of withdrawal, over such account. Other than any interest on the investment of such amounts in Cash Equivalents, which investments shall be made at the direction of the Borrower (unless an Unmatured Default or Event of Default shall have occurred and be continuing, in which case the determination as to investments shall be made at the option and in the discretion of the Administrative Agent), amounts in the Cash Collateral Account shall not bear interest. Interest and profits, if any, on such investments shall accumulate in such account. In the event of a drawing, and subsequent payment by any Issuing Bank, under any Letter of Credit at any time during which any amounts are held in the Cash Collateral Account, the Administrative Agent will deliver to such Issuing Bank an amount equal to the Reimbursement Obligation created as a result of such payment (or, if the amounts so held are less than such Reimbursement Obligation, all of such amounts) to reimburse such Issuing Bank therefor. Any amounts remaining in the Cash Collateral Account (including interest) after the expiration of all Letters of Credit and reimbursement in full of the Issuing Banks for all of its obligations thereunder shall be held by the Administrative Agent, for the benefit of the Borrower, to be applied against the Obligations in such order and manner as the Administrative Agent may direct.

3.9 The Issuing Bank . The Issuing Banks shall act on behalf of the Lenders with respect to any Letters of Credit issued by it and the documents associated therewith, and the Issuing Banks shall have all of the rights, benefits and immunities (a) provided to the Administrative Agent in ARTICLE X with respect to any acts taken or omissions suffered by it in connection with Letters of Credit issued by it or proposed to be issued by it and any documents pertaining to such Letters of Credit as fully as if the term "Administrative Agent" as used in ARTICLE X included the Issuing Banks with respect to such acts or omissions, and (b) as additionally provided herein with respect to the Issuing Banks.

3.10 Effectiveness . Notwithstanding any termination of the Commitments or repayment of the Loans, or both, the obligations of the Borrower under this ARTICLE III shall remain in full force and effect until the Issuing Banks and the Lenders shall have no further obligations to make any payments or disbursements under any circumstances with respect to any Letter of Credit.

ARTICLE IV

CONDITIONS PRECEDENT

4.1 Conditions to Agreement Date . The obligation of each Lender to make Loans and the obligation of the Issuing Banks to issue Letters of Credit hereunder on the Agreement Date, is subject to the satisfaction of the following conditions precedent:

(a) The Administrative Agent shall have received the following, each dated as of the Agreement Date (unless otherwise specified) and in such number of copies as the Administrative Agent shall have requested:

(1) Fully executed counterparts of this Agreement from the Borrower, each Lender, the Issuing Bank, the Swingline Lender and the Administrative Agent.

(2) Copies of the articles or certificate of incorporation of the Borrower, together with all amendments thereto, and a certificate of good standing, each certified by the appropriate governmental officer in its jurisdictions of incorporation.

(3) Copies, certified by the Secretary or Assistant Secretary of the Borrower, of its by-laws and of its Board of Directors' resolutions and of resolutions or actions of any other body authorizing (i) the execution of the Loan Documents to which the Borrower is a party and (ii) borrowings hereunder by the Borrower in an aggregate amount up to $450,000,000.

(4) An incumbency certificate, executed by the Secretary or Assistant Secretary of the Borrower, which shall identify by name and title and bear the signatures of the Authorized Officers and any other officers of the Borrower authorized to sign the Loan Documents, upon which certificate the Administrative Agent and the Lenders shall be entitled to rely until informed of any change in writing by the Borrower.

(5) A certificate, signed by the chief financial officer of the Borrower, stating that the conditions specified in Section 4.2(b) and (c) have been satisfied.

(6) A written opinion of the Borrower's counsel, addressed to the Lenders substantially in the form of Exhibit 4.1(a)(6) .

(7) Any Notes requested by a Lender pursuant to Section 2.11 payable to the order of each such requesting Lender.

(8) Evidence that the Existing Credit Agreement has been or concurrently with the Agreement Date is being terminated.

(9) Evidence satisfactory to the Administrative Agent of any required Governmental Approvals or consents regarding this Agreement.

(b) The Borrower shall have paid (i) to the Arrangers, the fees required under the Fee Letters to be paid to them on the Agreement Date, (ii) to the Administrative Agent, the initial payment of the annual administrative fee described in the Administrative Fee Letter, and (iii) all other fees and reasonable expenses of the Arrangers, the Administrative Agent and the Lenders required hereunder or under any other Loan Document to be paid on or prior to the Agreement Date (including reasonable fees and expenses of counsel) in connection with this Agreement and the other Loan Documents.

Without limiting the generality of the provisions of the last paragraph of Section 10.3 , for purposes of determining compliance with the conditions specified in this Section 4.1 , each Lender that has signed this Agreement shall be deemed to have consented to, approved or accepted or to be satisfied with, each document or other matter required thereunder to be consented to or approved by or acceptable or satisfactory to a Lender unless the Administrative Agent shall have received notice from such Lender prior to the proposed Agreement Date specifying its objection thereto.

4.2 Conditions to All Credit Extensions . The Lenders shall not be required to make any Loan, including the initial Loan, and no Issuing Bank shall be required to issue any Letter of Credit, unless on the applicable date of the requested extension of credit:

(a) The Borrower shall have furnished to the Administrative Agent, with sufficient copies for each Lender, a certificate dated such date of the requested extension of credit and signed by an Authorized Officer of the Borrower, stating that after taking in account the making of such Loan or issuance of such Letter of Credit, and the repayment of any outstanding obligations of the Borrower with respect to commercial paper with the proceeds of such Loan, if applicable, the Borrower will not have exceeded the maximum aggregate principal amount that the Borrower is entitled to borrow from financial institutions or receive from the sale of commercial paper under Board of Directors' resolutions of the Borrower.

(b) There exists no Event of Default or Unmatured Default.

(c) The representations and warranties contained in Article V (other than, after the Agreement Date, the representations and warranties set forth in Sections 5.2(b), 5.3, 5.11(a), 5.11(b), 5.11(c), 5.11(f), 5.11(g), 5.11(h) and 5.11(i)) are true and correct as of such date of the requested extension of credit except to the extent any such representation or warranty is stated to relate solely to an earlier date, in which case such representation or warranty shall have been true and correct on and as of such earlier date.

(d) All legal matters incident to such extension of credit shall be satisfactory to the Lenders and their counsel (including, without limitation, evidence satisfactory to the Administrative Agent of any required Governmental Approvals or consents regarding such extension of credit).

Each request for an extension of credit shall constitute a representation and warranty by the Borrower that the conditions contained in Sections 4.2(a), (b) and (c) have been satisfied. Any Lender may require a duly completed compliance certificate in substantially the form of Exhibit 4.2 (a " Compliance Certificate ") as a condition to making a Loan.

ARTICLE V

REPRESENTATIONS AND WARRANTIES

The Borrower represents and warrants to the Lenders that:

5.1 Corporate Existence . Each of the Borrower and its Material Subsidiaries: (a) is a corporation duly organized and validly existing under the laws of the jurisdiction of its incorporation; (b) has all requisite corporate power, and has all material governmental licenses, authorizations, consents and approvals, necessary to own its assets and carry on its business as now being or as proposed to be conducted; and (c) is qualified to do business in all jurisdictions in which the nature of the business conducted by it makes such qualification necessary and where failure so to qualify would have a Material Adverse Effect.

5.2 Financial Condition .

(a) The consolidated balance sheet and statement of consolidated capitalization of the Borrower and its consolidated Subsidiaries, if any, as at September 30, 2011 and the related consolidated statements of income, cash flows, common stockholders' equity and income taxes of the Borrower and its consolidated Subsidiaries, if any, for the fiscal year ended on September 30, 2011, with the opinion thereon of Deloitte & Touche LLP, and the unaudited consolidated balance sheet of the Borrower and its consolidated Subsidiaries, if any, as at December 31, 2011 and the related consolidated statements of income and cash flows of the Borrower and its consolidated Subsidiaries, if any, for the applicable three-month period ended on such date, heretofore furnished to each of the Lenders are complete and correct and fairly present the consolidated financial condition of the Borrower and its consolidated Subsidiaries, if any, as at said date and the results of their operations for the fiscal year and the applicable three-month period ended on said dates (subject, in the case of financial statements as at December 31, 2011 to normal year-end audit adjustments), all in accordance with GAAP and practices applied on a consistent basis. Neither the Borrower nor any of its Material Subsidiaries had on said dates any material contingent liabilities, liabilities for taxes, unusual forward or long-term commitments or unrealized or anticipated losses from any unfavorable commitments, except as referred to or reflected or provided for in said balance sheets as at said dates.

(b) Since September 30, 2011, there has been no material adverse change in the consolidated financial condition or operations, or the prospects or business taken as a whole, of the Borrower and its consolidated Subsidiaries, if any, from that set forth in said financial statements as at said date.

5.3 Litigation . Other than as set out in Schedule 5.3 hereto, there are no legal or arbitral proceedings or any proceedings by or before any Governmental Authority, now pending or (to the knowledge of the Borrower) threatened against the Borrower or any of its Material Subsidiaries as to which there is a reasonable possibility of an adverse determination and which, if adversely determined, could have a Material Adverse Effect during the term of this Agreement.

5.4 No Breach . None of the execution and delivery of this Agreement and the Notes, the consummation of the transactions herein contemplated and compliance with the terms and provisions hereof will conflict with or result in a breach of, or require any consent under, the charter or by-laws of the Borrower, or any Applicable Law or regulation, or any order, writ, injunction or decree of any court or governmental authority or agency, or any agreement or instrument to which the Borrower or its Material Subsidiaries is a party or by which it is bound or to which it is subject or which is applicable to it, or constitute a default under any such agreement or instrument, or result in the creation or imposition of any Lien upon any of the revenues or assets of the Borrower or any of its Material Subsidiaries pursuant to the terms of any such agreement or instrument.

5.5 Corporate Action . The Borrower has all necessary corporate power and authority to execute, deliver and perform its obligations under this Agreement and the Notes and to consummate the transactions herein contemplated, and the execution, delivery and performance of this Agreement and the Notes, and the consummation of the transactions herein contemplated, by the Borrower have been duly authorized by all necessary corporate action on its part; and this Agreement has been duly and validly executed and delivered by the Borrower and constitutes, and each of the Notes when executed and delivered for value will constitute, its legal, valid and binding obligation, enforceable in accordance with its terms.

5.6 Regulatory Approval . No consent, approval, authorization or other action by, notice to, or registration or filing with, any Governmental Authority or other Person is or will be required as a condition to or otherwise in connection with the due execution, delivery and performance by the Borrower of this Agreement or any of the other Loan Documents to which it is or will be a party or the legality, validity or enforceability hereof or thereof, other than consents, authorizations and filings that have been (or on or prior to the Agreement Date will have been) made or obtained and that are (or on the Agreement Date will be) in full force and effect, which consents, authorizations and filings are listed on Schedule 5.6 .

5.7 Regulations U and X . The Borrower is not engaged in the business of extending credit for the purpose of purchasing or carrying margin stock, and no proceeds of any Loans will be used for a purpose which violates, or would be inconsistent with, F.R.S. Board Regulation U or X, or any official rulings on or interpretations of such regulations. Terms for which meanings are provided in Regulation U or Regulation X or any regulations substituted therefor, as from time to time in effect, are used in this Section 5.7 with such meanings.

5.8 Pension and Welfare Plans . The Borrower is in compliance with the applicable provisions of ERISA. During the twelve consecutive-month period prior to the date of the execution and delivery of this Agreement and prior to the date of any borrowing hereunder, no steps have been taken to terminate or completely or partially withdraw from any Pension Plan, and no contribution failure has occurred with respect to any Pension Plan sufficient to give rise to a Lien under section 302 (f) of ERISA. No condition exists or event or transaction has occurred with respect to any Pension Plan which might result in the incurrence by the Borrower or any member of the Controlled Group of any material liability, fine or penalty or which could reasonably be expected to have a Material Adverse Effect. Except as disclosed in Schedule 5.8 (" Employee Benefit Plans "), neither the Borrower nor any member of the Controlled Group has any contingent liability with respect to any post-retirement benefit under a Welfare Plan, other than liability for continuation coverage described in Part 6 of Title I of ERISA.

5.9 Accuracy of Information . All factual information heretofore or contemporaneously furnished by or on behalf of the Borrower in writing to the Administrative Agent or any Lender for purposes of or in connection with this Agreement or any transaction contemplated hereby is, and all other such factual information hereafter furnished by or on behalf of the Borrower to the Administrative Agent or any Lender will be, true and accurate in every material respect on the date as of which such information is dated or certified and as of the date of execution and delivery of this Agreement by the Administrative Agent and such Lender, and such information is not, or shall not be, as the case may be, incomplete by omitting to state any material fact necessary to make such information not misleading.

5.10 Taxes . United States Federal income tax returns of the Utility and those of its Subsidiaries that have filed their returns on a consolidated basis with the Utility have been examined and/or closed through the fiscal year of the Utility ended September 30, 2011. The Borrower and its Subsidiaries have filed all United States Federal income tax returns and all other material tax returns which are required to be filed by them and have paid all taxes due pursuant to such returns or pursuant to any assessment received by the Borrower or any of its Subsidiaries. The charges, accruals and reserves on the books of the Borrower and its Subsidiaries in respect of taxes and other governmental charges are, in the opinion of the Borrower, adequate.

5.11 Environmental Warranties . Except as previously disclosed in the SEC Disclosure Documents or on Schedule 5.11 :

(a) all facilities and property (including underlying groundwater) owned, operated or leased by the Borrower or any of its Subsidiaries are in material compliance with all Environmental Laws, except for such instances of noncompliance as are unlikely, singly or in the aggregate, to have a Material Adverse Effect;

(b) there have been no past, and there are no pending or threatened:

(1) claims, complaints, notices or requests for information received by the Borrower or any of its Subsidiaries with respect to any alleged violation of any Environmental Law or,

(2) complaints, notices or inquiries to the Borrower or any of its Subsidiaries regarding potential liability under any Environmental Law;

except as are unlikely, singly or in the aggregate, to have a Material Adverse Effect;

(c) to the Borrower's knowledge, there have been no Releases of Hazardous Materials at, on or under any property now or previously owned, operated or leased by the Borrower or any of its Subsidiaries that, singly or in the aggregate, are reasonably likely to have a Material Adverse Effect during the term of this Agreement;

(d) the Borrower and its Subsidiaries have been issued and are in material compliance with all permits, certificates, approvals, licenses and other authorizations relating to environmental matters and necessary for their businesses;

(e) no property now or previously owned, operated or leased by the Borrower or any of its Subsidiaries is listed or proposed for listing (with respect to owned property only) on the National Priorities List pursuant to CERCLA or on any similar state list of sites requiring investigation or cleanup;

(f) to the Borrower's knowledge, there are no underground storage tanks, active or abandoned, including petroleum storage tanks, on or under any property now or previously owned, operated or leased by the Borrower or any of its Subsidiaries that, singly or in aggregate, could have a Material Adverse Effect during the term of this Agreement;

(g) to the Borrower's knowledge, neither Borrower nor any of its Subsidiaries has directly transported or directly arranged for the transportation of any Hazardous Material to any location which is listed or proposed for listing on the National Priorities List pursuant to CERCLA, on the CERCLIS or on any similar state list or which is the subject of Federal, state or local enforcement actions or other investigations which may lead to material claims against the Borrower or such Subsidiary for any remedial work, damage to natural resources or personal injury, including claims under CERCLA that, singly or in the aggregate, are likely to have a Material Adverse Effect during the term of this Agreement;

(h) there are no polychlorinated biphenyls or friable asbestos present at any property now or previously owned, operated or leased by the Borrower or any of its Subsidiaries that, singly or in the aggregate, could have a Material Adverse Effect during the term of this Agreement; and

(i) no conditions exist at, on or under any property now or previously owned or leased by the Borrower or any of its Subsidiaries which, with the passage of time, or the giving of notice or both, would give rise to liability under any Environmental Law, which would have a Material Adverse Effect during the term of this Agreement.

5.12 Investment Company Act . Neither the Borrower nor any of its Subsidiaries is an “investment company” or a company “controlled” by an “investment company” within the meaning of the Investment Company Act of 1940, as amended.

5.13 Subsidiaries . Schedule 5.13 is a true and complete list of all Subsidiaries of the Borrower as of the Agreement Date.

5.14 OFAC; Anti-Terrorism Laws .

(a) Neither the Borrower nor any of it Subsidiaries (i) is a Sanctioned Person, (ii) has more than 10% of its assets in Sanctioned Countries, or (iii) derives more than 10% of its operating income from investments in, or transactions with, Sanctioned Persons or Sanctioned Countries. No part of the proceeds of any Loan hereunder will be used directly or indirectly to fund any operations in, finance any investments or activities in or make any payments to, a Sanctioned Person or a Sanctioned Country.

(b) Neither the making of the Loans hereunder nor the use of the proceeds thereof will violate the PATRIOT Act, the Trading with the Enemy Act, as amended, the Foreign Corrupt Practices Act or any of the foreign assets control regulations of the United States Treasury Department (31 CFR, Subtitle B, Chapter V, as amended) or any enabling legislation or executive order relating thereto. The Credit Parties are in compliance in all material respects with the PATRIOT Act.

ARTICLE VI

COVENANTS

During the term of this Agreement, unless the Required Lenders shall otherwise consent in writing:

6.1 Financial Statements . The Borrower shall deliver to the Administrative Agent (and, in the case of clauses (e), (f) and (g) below, to each of the Lenders):

(a) as soon as available and in any event within 50 days after the end of each of the first three fiscal quarterly periods of each fiscal year of the Borrower, a consolidated statement of income of the Borrower and its consolidated Subsidiaries for such period and for the period from the beginning of the respective fiscal year to the end of such period, and a consolidated statement of cash flows for the period from the beginning of the respective fiscal year to the end of such period, the related consolidated balance sheet as at the end of such period, all in reasonable detail and prepared in accordance with GAAP (subject to the absence of notes required by GAAP and subject to normal year-end adjustments) applied on a basis consistent with that of the preceding quarter or containing disclosure of the effect on the financial condition or results of operations of any change in the application of accounting principles and practices during such quarter, accompanied by a certificate of a senior financial officer of the Borrower, which certificate shall state that said financial statements fairly present the consolidated financial condition and results of operations of the Borrower and its consolidated Subsidiaries in accordance with GAAP, consistently applied, as at the end of, and for, such period (subject to normal year-end audit adjustments);

(b) as soon as available and in any event within 95 days after the end of each fiscal year of the Borrower, consolidated statements of income, common stockholders’ equity, cash flows, and income taxes of the Borrower and its consolidated Subsidiaries for such year and the related consolidated balance sheet and statement of capitalization at the end of such year, setting forth in each case in comparative form the corresponding figures for the preceding fiscal year, all in reasonable detail and prepared in accordance with GAAP (subject to the absence of notes required by GAAP and subject to normal year-end adjustments) applied on a basis consistent with that of the preceding quarter or containing disclosure of the effect on the financial condition or results of operations of any change in the application of accounting principles and practices during such quarter, and accompanied by an opinion thereon of independent certified public accountants of recognized national standing, which opinion shall state, without material qualification, that said financial statements fairly present the consolidated financial position and results of operations and cash flows of the Borrower and its consolidated Subsidiaries as at the end of, and for, such fiscal year;

(c) promptly upon their becoming available, notification of the filing of all registration statements, regular periodic reports, if any, and SEC Disclosure Documents which the Borrower shall have filed with the Securities and Exchange Commission (or any governmental agency substituted therefor) or any national securities exchange;

(d) promptly upon the mailing thereof to the shareholders of the Borrower generally, copies, if not publicly available, or notification of mailing, of all financial statements, reports and proxy statements so mailed;

(e) promptly after the Borrower knows or has reason to know that any Event of Default or Unmatured Default has occurred, a notice of such Event of Default or Unmatured Default, describing the same in reasonable detail, and indicating what action is being undertaken with respect to such Event of Default or Unmatured Default;

(f) immediately upon becoming aware of the institution of any steps by the Borrower or any other Person to terminate any Pension Plan or the complete or partial withdrawal from any Pension Plan by the Borrower or any member of its Controlled Group, or the failure to make a required contribution to any Pension Plan if such failure is sufficient to give rise to a Lien under section 302(f) of ERISA, or the taking of any action with respect to a Pension Plan which could result in the requirement that the Borrower furnish a bond or other security to the PBGC or such Pension Plan, or the occurrence of any event with respect to any Pension Plan which could result in the incurrence by the Borrower of any material liability, fine or penalty, or any material increase in the contingent liability of the Borrower with respect to any post-retirement Welfare Plan benefit, notice thereof and copies of all documentation relating thereto; and

(g) from time to time such other information regarding the business, affairs or financial condition of the Borrower or any of its Subsidiaries as any Lender or the Administrative Agent may reasonably request.

The Borrower will furnish to the Administrative Agent, at the time it furnishes each set of financial statements pursuant to clause (a) or (b) above, a Compliance Certificate, executed by an Authorized Officer of the Borrower.

Information required to be delivered pursuant to clause (a), (b) or (c) above shall be deemed to have been delivered on the date on which (i) such information is actually delivered to the Administrative Agent for distribution to the Lenders or (ii) such information (x) has been posted by the Borrower on the Borrower's website at www.wglholdings.com, or at www.sec.gov or www.ferc.gov and (y) the Borrower provides notice to the Lenders that such information is available and specifies one or more of the above websites on which such information is located. At the request of the Administrative Agent, the Borrower will provide, by electronic mail, electronic versions of all documents containing such information.

6.2 Litigation . The Borrower shall promptly give to each Lender notice of all legal or arbitral proceedings, and of all proceedings before any governmental or regulatory authority or agency, affecting the Borrower or its Material Subsidiaries, except proceedings as to which there is no reasonable possibility of an adverse determination or which, if adversely determined, would not have a Material Adverse Effect during the term of this Agreement.

6.3 Corporate Existence, Compliance with Laws, Taxes, Examination of Books, Insurance, etc . The Borrower shall, and shall cause each of its Material Subsidiaries to: preserve and maintain its corporate existence and all of its material rights, privileges and franchises if failure to maintain such existence, rights, privileges or franchises would materially and adversely affect the financial condition or operations of, or the business taken as a whole, of the Borrower and its Subsidiaries; comply with the requirements of all Applicable Laws, rules, regulations and orders of governmental or regulatory authorities if failure to comply with such requirements would materially and adversely affect the financial condition or operations of, or the business taken as a whole, of the Borrower and its Subsidiaries; pay and discharge all taxes, assessments and governmental charges or levies imposed on it or on its income or profits or on any of its property prior to the date on which penalties attach thereto, except for any such tax, assessment, charge or levy the payment of which is being contested in good faith and by proper proceedings and against which adequate reserves are being maintained; maintain all of its properties used or useful in its business in good working order and condition, ordinary wear and tear excepted; permit representatives of any Lender or the Administrative Agent, during normal business hours, to examine, copy and make extracts from its books and records, to inspect its properties, and to discuss its business and affairs with its officers, all to the extent reasonably requested by such Lender or the Administrative Agent (as the case may be); and keep insured by financially sound and reputable insurers all property of a character usually insured by corporations engaged in the same or similar business similarly situated against loss or damage of the kinds and in the amounts customarily insured against by such corporations and carry such other insurance as is usually carried by such corporations.

6.4 Use of Proceeds . The Borrower shall use the proceeds of the Loans hereunder for its general corporate purposes (in compliance with all applicable legal and regulatory requirements).

6.5 Environmental Covenant . The Borrower will, and will cause each of its Subsidiaries to:

(a) use and operate all of its facilities and properties in compliance with all Environmental Laws except for such noncompliance which, singly or in the aggregate, will not have a Material Adverse Effect, keep all necessary permits, approvals, certificates, licenses and other authorizations relating to environmental matters in effect and remain in compliance therewith, except where the failure to keep such permits, approvals, certificates, licenses or other authorizations, or any noncompliance with the provisions thereof, will not have a Material Adverse Effect, and handle all Hazardous Materials in compliance with all applicable Environmental Laws, except for any noncompliance that will not have a Material Adverse Effect;

(b) immediately notify the Administrative Agent and provide copies upon receipt of all written inquiries from any Governmental Authority, claims, complaints or notices relating to the condition of its facilities and properties or compliance with Environmental Laws which will have a Material Adverse Effect, and promptly cure and have dismissed with prejudice or investigate and contest in good faith any actions and proceedings relating to material compliance with Environmental Laws; and

(c) provide such information and certifications which the Administrative Agent may reasonably request from time to time to evidence compliance with this Section 6.5 .

6.6 Financial Covenan t. The Borrower will not permit the ratio of (i) its Consolidated Financial Indebtedness to (ii) its Consolidated Total Capitalization to exceed 0.65 to 1.0 at any time.

6.7 Utility Dividends . The Borrower shall not, and shall cause the Utility not to, enter into or permit to exist any restriction or other limitation on the ability of the Utility to pay dividends to the Borrower, other than restrictions and limitations required by Applicable Law or the terms of the Utility’s preferred stock.

6.8 Borrower’s Continued Ownership of Utility’s Common Stock . The Borrower shall continue to own 100% of common stock of the Utility and 99% of all issued and outstanding stock of the Utility.

ARTICLE VII

EVENTS OF DEFAULT

The occurrence of any one or more of the following events shall constitute an Event of Default:

7.1 The Borrower fails to pay (i) when and as required to be paid herein, any amount of principal of any Loan or any Reimbursement Obligation, or (ii) within three days after the same becomes due, any interest on any Loan or any fee due hereunder, or (iii) within five days after the same becomes due, any other amount payable hereunder or under any other Loan Document;

7.2 The Borrower or any of its Material Subsidiaries (i) shall default in the payment when due of any principal of or interest on any of its other Indebtedness having an aggregate principal amount of at least $25,000,000, (ii) shall default under any Hedge Agreement covering a notional amount of Indebtedness of at least $25,000,000, (iii) or fails to observe or perform any other agreement or condition relating to any note, agreement, indenture or other document evidencing or relating to any such Indebtedness; or any other event occurs, the effect of which is to cause, or (with the giving of any notice or the lapse of time or both) to permit the holder or holders of such Indebtedness (or a trustee or agent on behalf of such holder or holders) to cause, such Indebtedness to become due prior to its stated maturity.

7.3 Any representation, warranty or certification made or deemed made herein by the Borrower, or any certificate furnished to any Lender or the Administrative Agent pursuant to the provisions hereof, shall prove to have been false or misleading as of the time made, deemed made, or furnished in any material respect.

7.4 The Borrower shall default in the performance of its obligations under Section 6.1(e) , 6.6 or 6.8 hereof.

7.5 The Borrower shall default in the performance of any of its other obligations in this Agreement and such default shall continue unremedied for a period of 15 days after the earlier of (i) the date on which a senior officer of the Borrower becomes aware of such default, or (ii) the date on which notice thereof is given to the Borrower by the Administrative Agent or any Lender (through the Administrative Agent).

7.6 The Borrower or any of its Material Subsidiaries shall admit in writing its inability to, or be generally unable to, pay its debts as such debts become due.

7.7 The Borrower or any of its Material Subsidiaries shall (i) apply for or consent to the appointment of, or the taking of possession by, a receiver, custodian, trustee or liquidator of itself or of all or a substantial part of its property, (ii) make a general assignment for the benefit of its creditors, (iii) commence a voluntary case under the Bankruptcy Code (as now or hereafter in effect), (iv) file a petition seeking to take advantage of any other law relating to bankruptcy, insolvency, reorganization, winding-up, or composition or readjustment of debts, (v) fail to controvert in a timely and appropriate manner, or acquiesce in writing to, any petition filed against it in an involuntary case under the Bankruptcy Code, or (vi) take any corporate action for the purpose of effecting any of the foregoing.

7.8 A proceeding or case shall be commenced, without the application or consent of the Borrower or any of its Material Subsidiaries, in any court of competent jurisdiction, seeking (i) its liquidation, reorganization, dissolution or winding-up, or the composition or readjustment of its debts, (ii) the appointment of a trustee, receiver, custodian, liquidator or the like of the Borrower or such Material Subsidiary or of all or any substantial part of its assets, or (iii) similar relief in respect of the Borrower or such Material Subsidiary under any law relating to bankruptcy, insolvency, reorganization, winding-up or composition or adjustment of debts, and such proceeding or case shall continue undismissed, or an order, judgment or decree approving or ordering any of the foregoing shall be entered and continue unstayed and in effect, for a period of 60 days; or an order for relief against the Borrower or such Material Subsidiary shall be entered in an involuntary case under the Bankruptcy Code.

7.9 A final judgment or judgments for the payment of money in excess of $50,000,000 in the aggregate that is not covered by insurance, performance bonds or the like shall be rendered by a court or courts against the Borrower or any of its Subsidiaries, and the same shall not be discharged (or provision shall not be made for such discharge), or a stay of execution thereof shall not be procured, within 90 days from the date of entry thereof and the Borrower or the relevant Subsidiary shall not, within said period of 90 days, or such longer period during which execution of the same shall have been stayed, appeal therefrom and cause the execution thereof to be stayed during such appeal.

7.10 Any of the following events shall occur with respect to any Pension Plan:

(i) the institution of any steps by the Borrower, any member of its Controlled Group or any other Person to terminate a Pension Plan if, as a result of such termination, the Borrower or any such member could be required to make a contribution to such Pension Plan, or could reasonably expect to incur a liability or obligation to such Pension Plan, in excess of $50,000,000; or

(ii) the complete or partial withdrawal from any Pension Plan by the Borrower or any member of its Controlled Group if, as a result of such withdrawal, the Borrower or any such member could incur any liability by such Pension Plan in excess of $50,000,000; or

(iii) a contribution failure occurs with respect to any Pension Plan sufficient to give rise to a Lien under Section 302(f) of ERISA.

7.11 Any license, consent, authorization or approval, filing or registration now or hereafter necessary to enable the Borrower to comply with its obligations hereunder or under the Notes shall be revoked, withdrawn, withheld or not effected or shall cease to be in full force and effect.

7.12 The occurrence of any Change in Control.

ARTICLE VIII

REMEDIES, WAIVERS AND AMENDMENTS

8.1 Remedies Upon Event of Default . If any Event of Default occurs and is continuing, the Administrative Agent shall, at the request of, or may, with the consent of, the Required Lenders, take any or all of the following actions:

8.1.1 declare the commitment of each Lender to make Loans and any obligation of the Issuing Banks to issue Letters of Credit to be terminated, whereupon such commitments and obligation shall be terminated;

8.1.2 declare the unpaid principal amount of all outstanding Loans, all interest accrued and unpaid thereon, and all other amounts owing or payable hereunder or under any other Loan Document to be immediately due and payable, without presentment, demand, protest or other notice of any kind, all of which are hereby expressly waived by the Borrower;

8.1.3 require that the Borrower Cash Collateralize the aggregate Stated Amount of outstanding Letters of Credit (in an amount equal to 102% of the aggregate Stated Amount thereof); and

8.1.4 exercise on behalf of itself, the Lenders and the Issuing Banks all rights and remedies available to it, the Lenders and the Issuing Banks under the Loan Documents;

provided , however , that upon the occurrence of any Event of Default described in Section 7.6 , 7.7 or 7.8 occurs with respect to the Borrower, the obligation of each Lender to make Loans and any obligation of any Issuing Bank to issue Letters of Credit shall automatically terminate, the unpaid principal amount of all outstanding Loans and all interest and other amounts as aforesaid shall automatically become due and payable, and the obligation of the Borrower to Cash Collateralize the aggregate Stated Amount of Letters of Credit as aforesaid shall automatically become effective, in each case without further act of the Administrative Agent or any Lender.

If, within 30 days after acceleration of the maturity of the Obligations or termination of the obligations of the Lenders to make Loans hereunder as a result of any Event of Default (other than any Event of Default as described in Section 7.6 , 7.7 or 7.8) and before any judgment or decree for the payment of the Obligations due shall have been obtained or entered, the Required Lenders (in their sole discretion) shall so direct, the Administrative Agent shall, by notice to the Borrower, rescind and annul such acceleration and/or termination.

8.2 Amendments . Subject to the provisions of this Article VIII , the Required Lenders (or the Administrative Agent with the consent in writing of the Required Lenders) and the Borrower may enter into agreements supplemental hereto for the purpose of adding or modifying any provisions to the Loan Documents or changing in any manner the rights of the Lenders or the Borrower hereunder or waiving any Event of Default hereunder; provided , however , that no such supplemental agreement shall, without the consent of each Lender affected thereby:

(i) Extend the final maturity of any Loan or forgive all or any portion of the principal amount thereof, or reduce the rate or extend the time of payment of interest or fees thereon;

(ii) Increase any Commitment of any such Lender over the amount thereof in effect or extend the maturity thereof (it being understood that a waiver of any condition precedent set forth in Section 4.2 or of any Unmatured Default or Event of Default or mandatory reduction in the Commitments, if agreed to by the Required Lenders or all Lenders (as may be required hereunder with respect to such waiver), shall not constitute such an increase);

(iii) Reduce the percentage specified in the definition of Required Lenders;

(iv) Extend the Facility Termination Date (except as set forth in Section 2.6), increase the period by which the Repayment Date may be extended, reduce the amount or extend the payment date for, the mandatory payments required under Section 2.1.2 , increase the amount the Commitment of such Lender hereunder (without the consent of such Lender), or permit the Borrower to assign its rights under this Agreement;

(v) Alter any provision in this Agreement providing for the pro rata treatment of the Lenders;

(vi) Amend this Section 8.2 or any provision of this Agreement requiring the consent or other action of all of the Lenders; or

(vii) Unless agreed to in writing by the Issuing Banks, the Swingline Lender or the Administrative Agent in addition to the Lenders required as provided hereinabove to take such action, affect the respective rights or obligations of the Issuing Bank, the Swingline Lender or the Administrative Agent, as applicable, hereunder or under any of the other Loan Documents.

Notwithstanding the fact that the consent of all Lenders is required in certain circumstances as set forth above, each Lender is entitled to vote as such Lender sees fit on any bankruptcy reorganization plan that affects the Loans, and each Lender acknowledges that the provisions of Section 1126(c) of the Bankruptcy Code supersedes the unanimous consent provisions set forth herein.

Notwithstanding anything to the contrary herein, (i) no Defaulting Lender shall have any right to approve or disapprove any amendment, waiver or consent hereunder (and any amendment, waiver or consent which by its terms requires the consent of all Lenders or each affected Lender may be effected with the consent of the applicable Lenders other than Defaulting Lenders), except that (x) the Commitment of any Defaulting Lender may not be increased or extended without the consent of such Lender and (y) any waiver, amendment or modification requiring the consent of all Lenders or each affected Lender that by its terms affects any Defaulting Lender more adversely than other affected Lenders shall require the consent of such Defaulting Lender and (ii) if the Administrative Agent and the Borrower shall have jointly identified (each in its sole discretion) an obvious error or omission of a technical or immaterial nature, in each case, in any provision of the Loan Documents, then the Administrative Agent and the Borrower shall be permitted to amend such provision and such amendment shall become effective without any further action or consent of any other party to any Loan Document if the same is not objected to in writing by the Required Lenders within five Business Days following the posting of such amendment to the Lenders.

No amendment of any provision of this Agreement relating to the Administrative Agent shall be effective without the written consent of the Administrative Agent. The Administrative Agent may waive payment of the fee required under Section 12.3.2 without obtaining the consent of any other party to this Agreement.

8.3 Preservation of Rights . No delay or omission of the Lenders or the Administrative Agent to exercise any right under the Loan Documents shall impair such right or be construed to be a waiver of any Event of Default or an acquiescence therein, and the making of a Loan notwithstanding the existence of an Event of Default or the inability of the Borrower to satisfy the conditions precedent to such Loan shall not constitute any waiver or acquiescence. Any single or partial exercise of any such right shall not preclude other or further exercise thereof or the exercise of any other right, and no waiver, amendment or other variation of the terms, conditions or provisions of the Loan Documents whatsoever shall be valid unless in writing signed by the Lenders required pursuant to Section 8.2 , and then only to the extent in such writing specifically set forth. All remedies contained in the Loan Documents or by law afforded shall be cumulative and all shall be available to the Administrative Agent and the Lenders until the Obligations have been paid in full.

ARTICLE IX

GENERAL PROVISIONS

9.1 Survival of Representation s. All representations and warranties of the Borrower contained in this Agreement shall survive during the period that the Loans herein contemplated are outstanding.

9.2 Governmental Regulation . Anything contained in this Agreement to the contrary notwithstanding, no Lender shall be obligated to extend credit to the Borrower in violation of any limitation or prohibition provided by any Applicable Law.

9.3 Headings . Headings to Articles, Sections and subsections of, and Annexes, Schedules and Exhibits to the Loan Documents are for convenience of reference only, and shall not govern the interpretation of any of the provisions of the Loan Documents.

9.4 Entire Agreement . The Loan Documents embody the entire agreement and understanding among the Borrower, the Administrative Agent and the Lenders and supersede all prior agreements and understandings among the Borrower, the Administrative Agent and the Lenders relating to the subject matter thereof.

9.5 Several Obligations; Benefits of this Agreement . The respective obligations of the Lenders hereunder are several and not joint and no Lender shall be the partner or agent of any other (except to the extent to which the Administrative Agent is authorized to act as such). The failure of any Lender to perform any of its obligations hereunder shall not relieve any other Lender from any of its obligations hereunder. This Agreement shall not be construed so as to confer any right or benefit upon any Person other than the parties to this Agreement and their respective successors and assigns; provided, however, that the parties hereto expressly agree that the Arrangers shall enjoy the benefits of the provisions of Sections 9.6, 9.10 and 9.11 to the extent specifically set forth therein and shall have the right to enforce such provisions on its own behalf and in its own name to the same extent as if it were a party to this Agreement.

9.6 Expenses; Indemnification.

9.6.1 Expenses. The Borrower shall pay:

(i) the Administrative Agent and the Arrangers for any reasonable costs, internal charges and out of pocket expenses (including attorneys' fees and time charges of attorneys for the Administrative Agent, which attorneys may be employees of the Administrative Agent) paid or incurred by the Administrative Agent or the Arrangers, and their respective Affiliates, in connection with the preparation, negotiation, execution, delivery, syndication, review, amendment, modification, and administration of the Loan Documents;

(ii) the Administrative Agent, the Arrangers, the Issuing Banks and the Lenders for any reasonable costs, internal charges and out of pocket expenses (including attorneys' fees and time charges of attorneys for the Administrative Agent, the Arrangers, the Issuing Banks and the Lenders, which attorneys may be employees of the Administrative Agent, the Arrangers, the Issuing Banks or the Lenders) paid or incurred by the Administrative Agent, the Arrangers, the Issuing Banks or any Lender in connection with the collection and enforcement of its rights (A) in connection with this Agreement and the other Loan Documents, including its rights under this Section 9.6, or (B) in connection with the Loans made or Letters of Credit issued hereunder, including all such out of pocket expenses incurred during any workout, restructuring or negotiations in respect of such Loans or Letters of Credit;

(iii) the Issuing Banks in connection with the issuance of any Letter of Credit or demand for payment thereunder; and

(iv) any civil penalty or fine assessed by OFAC against, and all reasonable costs and expenses (including counsel fees and disbursements) incurred in connection with defense thereof by, the Administrative Agent, any Issuing Bank or any Lender as a result of conduct of the Borrower that violates a sanction enforced by OFAC.

9.6.2 Indemnification by the Borrower. The Borrower shall indemnify the Administrative Agent (and any sub-agent thereof), each Lender, each Issuing Bank and each Related Party of any of the foregoing persons (each such person being called an "Indemnitee") against, and hold each Indemnitee harmless from, any and all losses, claims, damages, liabilities and related expenses (including the fees, charges and disbursements of any counsel for any Indemnitee), incurred by any Indemnitee or asserted against any Indemnitee by any Person (including the Borrower and any of its Subsidiaries) other than such Indemnitee and its Related Parties arising out of, in connection with, or as a result of (i) the execution or delivery of this Agreement, any other Loan Document or any agreement or instrument contemplated hereby or thereby, the performance by the parties hereto of their respective obligations hereunder or thereunder or the consummation of the transactions contemplated hereby or thereby, (ii) any Loan or Letter of Credit or the use or proposed use of the proceeds therefrom (including any refusal by the Issuing Bank to honor a demand for payment under a Letter of Credit if the documents presented in connection with such demand do not strictly comply with the terms of such Letter of Credit), (iii) any actual or alleged presence or release of Hazardous Material on or from any property owned or operated by the Borrower of any of its Subsidiaries, or any environmental claim related in any way the Borrower or its Subsidiaries, or (iv) any actual or prospective claim, litigation, investigation or proceeding relating to any of the foregoing, whether based on contract, tort or any other theory, whether brought by a third party or by the Borrower or its Subsidiaries, and regardless of whether any Indemnitee is a party thereto; provided that such indemnity shall not, as to any Indemnitee, be available to the extent that such losses, claims, damages, liabilities or related expenses (x) are determined by a court of competent jurisdiction by final and nonappealable judgment to have resulted from the gross negligence or willful misconduct of such Indemnitee or (y) result from a claim brought by the Borrower or any of its Subsidiaries against an Indemnitee for breach in bad faith of such Indemnitee's obligations hereunder or under any other Loan Document, if the Borrower or such Credit Party has obtained a final and nonappealable judgment in its favor on such claim as determined by a court of competent jurisdiction. This Section 9.6.2 shall not apply with respect to Taxes other than any Taxes that represent losses, claims, damages or related liabilities or expenses arising from any non-Tax claim.

9.6.3 Payments on Demand . All amounts due under this Section 9.6 shall be payable by the Borrower upon demand therefor.

9.7 Numbers of Documents . All statements, notices, closing documents, and requests hereunder shall be furnished to the Administrative Agent with sufficient counterparts so that the Administrative Agent may furnish one to each of the Lenders.

9.8 Accounting . Except as provided to the contrary herein, all accounting terms used herein shall be interpreted and all accounting determinations hereunder shall be made in accordance with GAAP, except that any calculation or determination which is to be made on a consolidated basis shall be made for the Borrower and all its Subsidiaries, including those Subsidiaries, if any, which are unconsolidated on the Borrower's audited financial statements.

9.9 Severability of Provisions . Any provision in any Loan Document that is held to be inoperative, unenforceable, or invalid in any jurisdiction shall, as to that jurisdiction, be inoperative, unenforceable or invalid without affecting the remaining provisions in that jurisdiction or the operation, enforceability or validity of that provision in any other jurisdiction, and to this end the provisions of all Loan Documents are declared to be severable. To the extent permitted by Applicable Law, the Borrower hereby waives any provision of Applicable Law that renders any provision of the Loan Documents prohibited or unenforceable in any respect.

9.10 Nonliability of Lenders . The relationship between the Borrower on the one hand and the Lenders and the Administrative Agent on the other hand shall be solely that of borrower and lender. Neither the Administrative Agent, the Arrangers, nor any Lender shall have any fiduciary responsibilities to the Borrower. Neither the Administrative Agent, the Arrangers, nor any Lender undertakes any responsibility to the Borrower to review or inform the Borrower of any matter in connection with any phase of the Borrower's business or operations. The Borrower agrees that neither the Administrative Agent, the Arrangers nor any Lender shall have liability to the Borrower (whether sounding in tort, contract or otherwise) for losses suffered by the Borrower in connection with, arising out of, or in any way related to, the transactions contemplated and the relationship established by the Loan Documents, or any act, omission or event occurring in connection therewith, unless it is determined in a final non-appealable judgment by a court of competent jurisdiction that such losses resulted from the gross negligence or willful misconduct of the party from which recovery is sought. Neither the Administrative Agent, the Arrangers nor any Lender shall have any liability with respect to, and the Borrower hereby waives, releases and agrees not to sue for, any special, indirect, punitive or consequential damages suffered by the Borrower in connection with, arising out of, or in any way related to the Loan Documents or the transactions contemplated thereby.

9.11 Confidentiality . Each Lender agrees to hold any confidential information which it may receive from the Borrower pursuant to this Agreement in confidence, except for disclosure (i) to its Affiliates and to other Lenders and their respective Affiliates, (ii) to legal counsel, accountants, and other professional advisors to such Lender or to a Transferee, (iii) to regulatory officials, (iv) to any Person as requested pursuant to or as required by Applicable Law, (v) to any Person in connection with any legal proceeding to which such Lender is a party, (vi) to such Lender's direct or indirect contractual counterparties in swap agreements or to legal counsel, accountants and other professional advisors to such counterparties, and (vii) permitted by Section 12.4 .

9.12 Disclosure . The Borrower and each Lender hereby acknowledge and agree that the Administrative Agent and/or its Affiliates from time to time may hold investments in, make other loans to or have other relationships with the Borrower and its Affiliates.

9.13 Rights Cumulative . Each of the rights and remedies of the Administrative Agent and the Lenders under the Loan Documents shall be in addition to all of their other rights and remedies under the Loan Documents and Applicable Law, and nothing in the Loan Documents shall be construed as limiting any such rights or remedies.

9.14 Syndication Agent; Documentation Agents . Neither the Syndication Agent nor the Documentation Agents shall have any liability or obligation whatsoever to the Borrower, the Administrative Agent or any Lender at any time under this Agreement, other than its obligations as a Lender hereunder.

ARTICLE X

THE ADMINISTRATIVE AGENT

10.1 Appointment and Authority . Each of the Lenders (for purposes of this ARTICLE X , references to the Lenders shall also mean the Issuing Bank and the Swingline Lender) hereby irrevocably appoints Wells Fargo to act on its behalf as the Administrative Agent hereunder and under the other Loan Documents and authorizes the Administrative Agent to take such actions on its behalf and to exercise such powers as are delegated to the Administrative Agent by the terms hereof or thereof, together with such actions and powers as are reasonably incidental thereto. Except as set forth in Section 10.6 , the provisions of this ARTICLE X are solely for the benefit of the Administrative Agent and the Lenders, and neither the Borrower nor of its Subsidiaries shall have rights as a third-party beneficiary of any of such provisions. It is understood and agreed that the use of the term “agent” (or any other similar term) herein or in any other Loan Document with reference to the Administrative Agent is not intended to connote any fiduciary or other implied (or express) obligations under agency doctrine of any Applicable Law. Instead, such term is used as a matter of market custom, and is intended to create or reflect only an administrative relationship between contracting parties.

10.2 Rights as a Lender . The Person serving as the Administrative Agent hereunder shall have the same rights and powers in its capacity as a Lender as any other Lender and may exercise the same as though it were not the Administrative Agent, and the term “ Lender ” or “ Lenders ” shall, unless otherwise expressly indicated or unless the context otherwise requires, include the Person serving as the Administrative Agent hereunder in its individual capacity. Such Person and its Affiliates may accept deposits from, lend money to, own securities of, act as the financial advisor or in any other advisory capacity for and generally engage in any kind of business with the Borrower or any Subsidiary or other Affiliate thereof as if such Person were not the Administrative Agent hereunder and without any duty to account therefor to the Lenders.

10.3 Exculpatory Provisions .

10.3.1 The Administrative Agent shall not have any duties or obligations except those expressly set forth herein and in the other Loan Documents, and its duties hereunder shall be administrative in nature. Without limiting the generality of the foregoing, the Administrative Agent:

(i) shall not be subject to any fiduciary or other implied duties, regardless of whether an Unmatured Default or Event of Default has occurred and is continuing;

(ii) shall not have any duty to take any discretionary action or exercise any discretionary powers, except discretionary rights and powers expressly contemplated hereby or by the other Loan Documents that the Administrative Agent is required to exercise as directed in writing by the Required Lenders (or such other number or percentage of the Lenders as shall be expressly provided for herein or in the other Loan Documents); provided that the Administrative Agent shall not be required to take any action that, in its opinion or the opinion of its counsel, may expose the Administrative Agent to liability or that is contrary to any Loan Document or Applicable Law, including, for the avoidance of doubt, any action that may be in violation of the automatic stay under any the Bankruptcy Code or under other applicable bankruptcy, insolvency or similar law now or hereafter in effect or that may effect a forfeiture, modification or termination of property of a Defaulting Lender in violation of the Bankruptcy Code or any other applicable bankruptcy insolvency or similar law now or hereafter in effect; and

(iii) shall not, except as expressly set forth herein and in the other Loan Documents, have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Borrower or any of its Affiliates that is communicated to or obtained by the Person serving as the Administrative Agent or any of its Affiliates in any capacity.

10.3.2 The Administrative Agent shall not be liable for any action taken or not taken by it (i) with the consent or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as the Administrative Agent shall believe in good faith shall be necessary, under the circumstances as provided in Sections 8.2 and 8.1), or (ii) in the absence of its own gross negligence or willful misconduct as determined by a court of competent jurisdiction by final and nonappealable judgment. The Administrative Agent shall be deemed not to have knowledge of any Unmatured Default or Event of Default unless and until notice describing such Unmatured Default or Event of Default is given to the Administrative Agent in writing by the Borrower or a Lender.

10.3.3 The Administrative Agent shall not be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with this Agreement or any other Loan Document, (ii) the contents of any certificate, report or other document delivered hereunder or thereunder or in connection herewith or therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth herein or therein or the occurrence of any Unmatured Default or Event of Default, (iv) the validity, enforceability, effectiveness or genuineness of this Agreement, any other Loan Document or any other agreement, instrument or document or (v) the satisfaction of any condition set forth in ARTICLE IV or elsewhere herein, other than to confirm receipt of items expressly required to be delivered to the Administrative Agent.

10.4 Reliance by Administrative Agent . The Administrative Agent shall be entitled to rely upon, and shall not incur any liability for relying upon, any notice, request, certificate, consent, statement, instrument, document or other writing (including any electronic message, internet or intranet website posting or other distribution) believed by it to be genuine and to have been signed, sent or otherwise authenticated by the proper Person. The Administrative Agent also may rely upon any statement made to it orally or by telephone and believed by it to have been made by the proper Person, and shall not incur any liability for relying thereon. In determining compliance with any condition hereunder to the making of a Loan, or the issuance, extension, renewal or increase of a Letter of Credit, that by its terms must be fulfilled to the satisfaction of a Lender or the Issuing Bank, the Administrative Agent may presume that such condition is satisfactory to such Lender or the Issuing Bank unless the Administrative Agent shall have received notice to the contrary from such Lender or the Issuing Bank prior to the making of such Loan or the issuance, extension, renewal or increase of such Letter of Credit. The Administrative Agent may consult with legal counsel (who may be counsel for the Borrower), independent accountants and other experts selected by it, and shall not be liable for any action taken or not taken by it in accordance with the advice of any such counsel, accountants or experts.

10.5 Delegation of Duties . The Administrative Agent may perform any and all of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub-agents appointed by the Administrative Agent. The Administrative Agent and any such sub-agent may perform any and all of its duties and exercise its rights and powers by or through their respective Related Parties. The exculpatory provisions of this Article shall apply to any such sub-agent and to the Related Parties of the Administrative Agent and any such sub-agent, and shall apply to their respective activities in connection with the syndication of the credit facilities provided for herein as well as activities as Administrative Agent. The Administrative Agent shall not be responsible for the negligence or misconduct of any sub-agent except to the extent that a court of competent jurisdiction determines in a final and nonappealable judgment that the Administrative Agent acted with gross negligence or willful misconduct in the selection of such sub-agent.

10.6 Resignation of Administrative Agent.

10.6.1 Resignation Effective Date . The Administrative Agent may at any time give notice of its resignation to the Lenders and the Borrower. Upon receipt of any such notice of resignation, the Required Lenders shall have the right, in consultation with the Borrower, to appoint a successor, which shall be a bank with an office in the United States, or an Affiliate of any such bank with an office in the United States. If no such successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 30 days after the retiring Administrative Agent gives notice of its resignation (or such earlier day as shall be agreed by the Required Lenders) (the " Resignation Effective Date "), then the retiring Administrative Agent may (but shall not be obligated to), on behalf of the Lenders, appoint a successor Administrative Agent meeting the qualifications set forth above. Regardless of whether a successor has been appointed or has accepted such appointment, such resignation shall become effective in accordance with such note on the Resignation Effective Date.

10.6.2 Discharge of Duties After Resignation . With effect from the Resignation Effective Date, (i) the retiring Administrative Agent shall be discharged from its duties and obligations hereunder and under the other Loan Documents (except that in the case of any collateral security held by the Administrative Agent on behalf of the Lenders under any of the Loan Documents, the retiring Administrative Agent shall continue to hold such collateral security until such time as a successor Administrative Agent is appointed) and (ii) except for any indemnity payments owed to the retiring Administrative Agent, all payments, communications and determinations provided to be made by, to or through the Administrative Agent shall instead be made by or to each Lender directly, until such time, if any, as the Required Lenders appoint a successor Administrative Agent as provided for in Section 10.6.1 . Upon the acceptance of a successor's appointment as Administrative Agent hereunder, such successor shall succeed to and become vested with all of the rights, powers, privileges and duties of the retiring Administrative Agent (other than any rights to indemnity payments owed to the retiring Administrative Agent), and the retiring Administrative Agent shall be discharged from all of its duties and obligations hereunder or under the other Loan Documents. The fees payable by the Borrower to a successor Administrative Agent shall be the same as those payable to its predecessor unless otherwise agreed between the Borrower and such successor. After the retiring Administrative Agent's resignation hereunder and under the other Loan Documents, the provisions of this ARTICLE X and Section 9.6 shall continue in effect for the benefit of such retiring Administrative Agent, its sub-agents and their respective Related Parties in respect of any actions taken or omitted to be taken by any of them while the retiring Administrative Agent was acting as Administrative Agent.

10.7 Non-Reliance on Administrative Agent and Other Lenders . Each Lender acknowledges that it has, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement. Each Lender also acknowledges that it will, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder.

10.8 No Other Duties, etc . Anything herein to the contrary notwithstanding, none of the Arrangers, Syndication Agent, Documentation Agents or other agents listed on the cover page hereof shall have any powers, duties or responsibilities under this Agreement or any of the other Loan Documents, except in its capacity, as applicable, as the Administrative Agent or a Lender hereunder.

10.9 Administrative Agent May File Proofs of Claim . In case of the pendency of any proceeding under the Bankruptcy Code or under other applicable bankruptcy, insolvency or similar law now or hereafter in effect or any other judicial proceeding relative to the Borrower or any of its Subsidiaries, the Administrative Agent (irrespective of whether the principal of any Loan or Reimbursement Obligation shall then be due and payable as herein expressed or by declaration or otherwise and irrespective of whether the Administrative Agent shall have made any demand on the Borrower) shall be entitled and empowered (but not obligated) by intervention in such proceeding or otherwise (i) to file and prove a claim for the whole amount of the principal and interest owing and unpaid in respect of the Loans, Reimbursement Obligations and all other Obligations that are owing and unpaid and to file such other documents as may be necessary advisable in order to have the claims of the Lenders and the Administrative Agent (including any claim for the reasonable compensation, expenses, disbursements and advances of the Lenders and the Administrative Agent and their respective agents, sub-agents and counsel and all other amounts due the Lenders and the Administrative Agent under Sections 2.4 and 9.6) allowed in such judicial proceeding and (ii) to collect and receive any monies or other property payable or deliverable on any such claims and to distribute the same. Any custodian, receiver, assignee, trustee, liquidator, sequestrator or other similar official in any such judicial proceeding is hereby authorized by each Lender to make such payments to the Administrative Agent and, in the event that the Administrative Agent shall consent to the making of such payments to the Lenders, to pay to the Administrative Agent any amount due for the reasonable compensation, expenses, disbursements and advances of the Administrative Agent and its agents, sub-agents and counsel, and any other amounts due the Administrative Agent under Section 2.4 or 9.6 .

10.10 Issuing Bank and Swingline Lender . The provisions of this ARTICLE X (other than Section 10.2) shall apply to the Issuing Bank and the Swingline Lender mutatis mutandis to the same extent as such provisions apply to the Administrative Agent.

ARTICLE XI

SETOFF; RATABLE PAYMENTS

11.1 Setoff . In addition to, and without limitation of, any rights of the Lenders under Applicable Law, if the Borrower becomes insolvent, however evidenced, or any Event of Default occurs, each Lender, the Issuing Banks and each of their respective Affiliates is hereby authorized at any time and from time to time, to the fullest extent permitted by Applicable Law, to set off and apply any and all deposits (general or special, time or demand, provisional or final, in whatever currency) at any time held, and other obligations (in whatever currency) at any time owing, by such Lender, such Issuing Bank or any such Affiliate, to or for the credit or the account of the Borrower against any and all of the obligations of the Borrower now or hereafter existing under this Agreement or any other Loan Document to such Lender or such Issuing Bank or their respective Affiliates, irrespective of whether or not such Lender, such Issuing Bank or such Affiliate shall have made any demand under this Agreement or any other Loan Document and although such obligations of the Borrower may be contingent or unmatured or are owed to a branch, office or Affiliate of such Lender or such Issuing Bank different from the branch, office or Affiliate holding such deposit or obligated on such indebtedness; provided that in the event that any Defaulting Lender shall exercise any such right of setoff, (i) all amounts so set off shall be paid over immediately to the Administrative Agent for further application in accordance with the provisions of Section 2.18 and, pending such payment, shall be segregated by such Defaulting Lender from its other funds and deemed held in trust for the benefit of the Administrative Agent, the Issuing Banks and the Lenders (including the Swingline Lender), and (ii) the Defaulting Lender shall provide promptly to the Administrative Agent a statement describing in reasonable detail the obligations owing to such Defaulting Lender as to which it exercised such right of setoff. The rights of each Lender, each Issuing Bank and their respective Affiliates under this Section 11.1 are in addition to other rights and remedies (including other rights of setoff) that such Lender, such Issuing Bank or their respective Affiliates may have. Each Lender and each Issuing Bank agrees to notify the Borrower and the Administrative Agent promptly after any such setoff and application; provided that the failure to give such notice shall not affect the validity of such setoff and application.

11.2 Ratable Payments . If any Lender, whether by setoff or otherwise, has payment made to it upon Obligations owing to it in a greater proportion than that received by any other Lender, such Lender agrees, promptly upon demand, to (i) notify the Administrative Agent of such fact and (ii) purchase participations (for cash at face value) in the Obligations held by the other Lenders so that after such acquisition each Lender will hold its ratable proportion of the then outstanding Obligations; provided that (i) if any such participations are purchased and all or any portion of the payment giving rise thereto is recovered, such participations shall be rescinded and the purchase price restored to the extent of such recovery, without interest, and (ii) the provisions of this Section 11.2 shall not be construed to apply to (x) any payment made by the Borrower pursuant to and in accordance with the express terms of this Agreement (including the application of funds arising from the existence of a Defaulting Lender) or (y) any payment obtained by a Lender as consideration for the assignment of or sale of a participation in any of its Loans or participations in Reimbursement Obligations or Swingline Loans to any assignee or Participant, other than to the Borrower or any Subsidiary thereof (as to which the provisions of this Section 11.2 shall apply). The Borrower consents to the foregoing and agrees, to the extent it may effectively do so under Applicable Law, that any Lender acquiring a participation pursuant to the foregoing arrangements may exercise against the Borrower rights of setoff and counterclaim with respect to such participation as fully as if such Lender were a direct creditor of the Borrower in the amount of such participation. If under the Bankruptcy Code or under other applicable bankruptcy, insolvency or similar law now or hereafter in effect, any Lender receives a secured claim in lieu of a setoff to which this Section 11 .2 applies, such Lender shall, to the extent practicable, exercise its rights in respect of such secured claim in a manner consistent with the rights of the Lenders entitled under this Section 11.2 to share in the benefits of any recovery on such secured claim. If any Lender, whether in connection with setoff or amounts which might be subject to setoff or otherwise, receives collateral or other protection for its Obligations or other amounts which may be subject to setoff, such Lender agrees, promptly upon demand, to take such action necessary such that all Lenders share in the benefits of such collateral or other protection ratably in proportion to their Loans. In case any such payment is disturbed by legal process, or otherwise, appropriate further adjustments shall be made.

ARTICLE XII

BENEFIT OF AGREEMENT; ASSIGNMENTS; PARTICIPATIONS

12.1 Successors and Assigns . The terms and provisions of the Loan Documents shall be binding upon and inure to the benefit of the Borrower and the Lenders and their respective successors and assigns, except that (i) the Borrower shall not have the right to assign its rights or obligations under the Loan Documents and (ii) any assignment by any Lender must be made in compliance with Section 12.3 . The parties to this Agreement acknowledge that clause (ii) of this Section 12.1 relates only to absolute assignments and does not prohibit assignments creating security interests, including, without limitation, any pledge or assignment by any Lender of all or any portion of its rights under this Agreement and any Note to a Federal Reserve Bank; provided , however , that no such pledge or assignment creating a security interest shall release the transferor Lender from its obligations hereunder unless and until the parties thereto have complied with the provisions of Section 12.3 . The Administrative Agent may treat the Person which made any Loan or which holds any Note as the owner thereof for all purposes hereof unless and until such Person complies with Section 12.3 ; provided , however , that the Administrative Agent may in its discretion (but shall not be required to) follow instructions from the Person which made any Loan or which holds any Note to direct payments relating to such Loan or Note to another Person. Any assignee of the rights to any Loan or any Note agrees by acceptance of such assignment to be bound by all the terms and provisions of the Loan Documents. Any request, authority or consent of any Person, who at the time of making such request or giving such authority or consent is the owner of the rights to any Loan (whether or not a Note has been issued in evidence thereof), shall be conclusive and binding on any subsequent holder or assignee of the rights to such Loan.

12.2 Participations .

12.2.1 Permitted Participants; Effect . Any Lender may, in the ordinary course of its business and in accordance with Applicable Law, at any time sell to one or more banks or other entities (" Participants ") participating interests in any Loan owing to such Lender, any Note held by such Lender, any Commitment of such Lender or any other interest of such Lender under the Loan Documents. In the event of any such sale by a Lender of participating interests to a Participant, such Lender's obligations under the Loan Documents shall remain unchanged, such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations, such Lender shall remain the owner of its Loans and the holder of any Note issued to it in evidence thereof for all purposes under the Loan Documents, all amounts payable by the Borrower under this Agreement shall be determined as if such Lender had not sold such participating interests, and the Borrower and the Administrative Agent shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under the Loan Documents. Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to enforce this Agreement and to approve any amendment, modification or waiver of any provision of this Agreement; provided that such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, waiver or other modification described in Section 8.2 that affects such Participant. The Borrower agrees that each Participant shall be entitled to the benefits of Sections 2.18.1 , 2.18.2 , 2.19 , and 2.20 to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to Section 12.3 ; provided that such Participant (A) agrees to be subject to the provisions of Section 2.21 as if it were an assignee under Section 12.3 and (B) shall not be entitled to receive any greater payment under Section 2.18 or 2.19 , with respect to any participation, than its participating Lender would have been entitled to receive, except to the extent such entitlement to receive a greater payment results from a Change in Law that occurs after the Participant acquired the applicable participation. Each Lender that sells a participation agrees, at the Borrower's request and expense, to use reasonable efforts to cooperate with the Borrower to effectuate the provisions of Section 2.21 with respect to any Participant. To the extent permitted by law, each Participant also shall be entitled to the benefits of Section 11.1 as though it were a Lender; provided that such Participant agrees to be subject to Section 11.2 as though it were a Lender. Each Lender that sells a participation shall, acting solely for this purpose as an agent of the Borrower, maintain a register on which it enters the name and address of each Participant and the principal amounts (and stated interest) of each Participant's interest in the Loans or other Obligations under the Loan Documents (the " Participant Register "); provided that no Lender shall have any obligation to disclose all or any portion of the Participant Register (including the identity of any Participant or any information relating to a Participant's interest in any Commitments, Loans, Letters of Credit or its other obligations under any Loan Document) to any Person except to the extent that such disclosure is necessary to establish such Commitment, Loan, Letter of Credit or other obligation is in registered form under Section 5f.103-1(c) of the United States Treasury Regulations. The entries in the Participant Register shall be conclusive absent manifest error, and such Lender shall treat each Person whose name is recorded in the Participant Register as the owner of such participation for all purposes of this Agreement. For the avoidance of doubt, the Administrative Agent (in its capacity as Administrative Agent) shall have no responsibility for maintaining a Participant Register.

12.2.2 Certain Pledges . Any Lender may at any time pledge or assign a security interest in all or any portion of its rights under this Agreement (including under its Notes, if any) to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank; provided that no such pledge or assignment shall release such Lender from any of its obligations hereunder or substitute any such pledgee or assignee for such Lender as a party hereto.

12.3 Assignments .

12.3.1 Permitted Assignments . Any Lender may, in the ordinary course of its business and in accordance with Applicable Law, at any time assign to one or more banks or other entities (" Purchasers ") all or any part of its rights and obligations under the Loan Documents. Such assignment shall be pursuant to an agreement substantially in the form of Exhibit 12.3.1 . The consent of the Borrower and the Administrative Agent shall be required prior to an assignment becoming effective with respect to a Purchaser which is not a Lender or an Affiliate thereof; provided , however , that if an Event of Default has occurred and is continuing, the consent of the Borrower shall not be required; provided further that the Borrower shall be deemed to have consented to any such assignment unless it shall object thereto by written notice to the Administrative Agent within five Business Days after having received notice thereof. Such consent shall not be unreasonably withheld or delayed. Each such assignment with respect to a Purchaser which is not a Lender or an Affiliate thereof shall (unless each of the Borrower and the Administrative Agent otherwise consents) be in an amount not less than the lesser of (i) $5,000,000 or (ii) the remaining amount of the assigning Lender's Commitment (calculated as at the date of such assignment) or outstanding Loans (if the applicable Commitment has been terminated). The consent of the Issuing Banks (such consent not to be unreasonably withheld or delayed) shall be required for any assignment that increases the obligation of the assignee to participate in exposure under one or more Letters of Credit (whether or not then outstanding). The consent of the Swingline Lender (such consent not to be unreasonably withheld or delayed) shall be required for any assignment hereunder. No such assignment shall be made to (A) a natural person, (B) the Borrower or any of its respective Affiliates or Subsidiaries or (C) to any Defaulting Lender or any of its Subsidiaries, or any Person who, upon becoming a Lender hereunder, would constitute any of the foregoing Persons described in this clause.

12.3.2 Effect; Effective Date . Upon (i) delivery to the Administrative Agent of an assignment, together with any consents required by Section 12.3.1 , and (ii) payment of a $3,500 fee to the Administrative Agent for processing such assignment (unless such fee is waived by the Administrative Agent), such assignment shall become effective on the effective date specified in such assignment. On and after the effective date of such assignment, such Purchaser shall for all purposes be a Lender party to this Agreement and any other Loan Document executed by or on behalf of the Lenders and shall have all the rights and obligations of a Lender under the Loan Documents, to the same extent as if it were an original party hereto, and no further consent or action by the Borrower, the Lenders or the Administrative Agent shall be required to release the transferor Lender with respect to the percentage of the Aggregate Commitments assigned to such Purchaser but such transferor Lender shall continue to be entitled to the benefits of Sections 2.18.1 , 2.18.2 , 2.19 , and 2.20 with respect to facts and circumstances occurring prior to the effective date of such assignment; provided that, except to the extent otherwise expressly agreed by the affected parties, no assignment by a Defaulting Lender will constitute a waiver or release of any claim of any party hereunder arising from such Lender's having been a Defaulting Lender. Upon the consummation of any assignment to a Purchaser pursuant to this Section 12.3.2 , the transferor Lender, the Administrative Agent and the Borrower shall, if the transferor Lender or the Purchaser desires that its Loans be evidenced by Notes, make appropriate arrangements so that new Notes or, as appropriate, replacement Notes are issued to such transferor Lender and new Notes or, as appropriate, replacement Notes, are issued to such Purchaser, in each case in principal amounts reflecting their respective Commitments, as adjusted pursuant to such assignment. Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this paragraph shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with Section 12.2.2 .

12.3.3 Assignments by a Defaulting Lender . In connection with any assignment of rights and obligations of any Defaulting Lender hereunder, no such assignment shall be effective unless and until, in addition to the other conditions thereto set forth herein, the parties to the assignment shall make such additional payments to the Administrative Agent in an aggregate amount sufficient, upon distribution thereof as appropriate (which may be outright payment, purchases by the assignee of participations or subparticipations, or other compensating actions, including funding, with the consent of the Borrower and the Administrative Agent, the Applicable Percentage of Loans previously requested but not funded by the Defaulting Lender, to each of which the applicable assignee and assignor hereby irrevocably consent), to (i) pay and satisfy in full all payment liabilities then owed by such Defaulting Lender to the Administrative Agent or any Lender hereunder (and interest accrued thereon), and (ii) acquire (and fund as appropriate) its full share of all Loans and participations in Letters of Credit and Swingline Loans in accordance with its Applicable Percentage. Notwithstanding the foregoing, in the event that any assignment of rights and obligations of any Defaulting Lender hereunder shall become effective under Applicable Law without compliance with the provisions of this paragraph, then the assignee of such interest shall be deemed to be a Defaulting Lender for all purposes of this Agreement until such compliance occurs.

12.3.4 Register . The Administrative Agent, acting solely for this purpose as an agent of the Borrower, shall maintain at its address for notices referred to in Schedule 1.1-B a copy of each Assignment and Assumption delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitments of, and principal amounts (and stated interest) of the Loans owing to, each Lender pursuant to the terms hereof from time to time (the " Register "). The entries in the Register shall be conclusive absent manifest error, and the Borrower, the Administrative Agent and the Lenders shall treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement. In addition, the Administrative Agent shall maintain on the Register information regarding the designation, revocation of designation, of any Lender as a Defaulting Lender. The Register shall be available for inspection by each of the Borrower and the Issuing Bank, at any reasonable time and from time to time upon reasonable prior notice.

12.4 Dissemination of Information . The Borrower authorizes each Lender to disclose to any Participant or Purchaser or any other Person acquiring an interest in the Loan Documents by operation of law (each a " Transferee ") and any prospective Transferee any and all information in such Lender's possession concerning the creditworthiness of the Borrower and its Subsidiaries; provided that each Transferee and prospective Transferee agrees to be bound by Section 9.11 of this Agreement.

12.5 Tax Treatment . If any interest in any Loan Document is transferred to any Transferee which is organized under the laws of any jurisdiction other than the United States or any State thereof, the transferor Lender shall cause such Transferee, concurrently with the effectiveness of such transfer, to comply with the provisions of Section 2.19 .

ARTICLE XIII

NOTICES

13.1 Notices . Except as otherwise permitted by Section 2.12 with respect to Borrowing Notices, Swingline Borrowing Notices and Continuation/Conversion Notices, all notices, requests and other communications to any party hereunder shall be in writing (including electronic transmission, facsimile transmission or similar writing) and shall be given to such party: (i) in the case of the Borrower or the Administrative Agent, at its address or facsimile number set forth on the signature pages hereof, (ii) in the case of any Lender, at its address or facsimile number set forth on its Administrative Questionnaire or (iii) in the case of any party, at such other address or facsimile number as such party may hereafter specify for the purpose by notice to the Administrative Agent and the Borrower in accordance with the provisions of this Section 13.1 . Each such notice, request or other communication shall be effective (x) if given by facsimile transmission, when transmitted to the facsimile number specified in this Section and confirmation of receipt is received, (y) if given by mail, 72 hours after such communication is deposited in the mails with first class postage prepaid, addressed as aforesaid, or (z) if given by any other means, when delivered (or, in the case of electronic transmission, received) at the address specified in this Section; provided that notices to the Administrative Agent under Article II shall not be effective until received.

13.2 Change of Address . The Borrower, the Administrative Agent and any Lender may each change the address for service of notice upon it by a notice in writing to the other parties hereto.

ARTICLE XIV

COUNTERPARTS; EFFECTIVENESS

This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one agreement, and any of the parties hereto may execute this Agreement by signing any such counterpart. This Agreement shall become effective when (a) it has been executed by the Borrower, the Administrative Agent and the Lenders and each party has notified the Administrative Agent by facsimile transmission or telephone that it has taken such action and (b) the Borrower has paid all outstanding fees and other amounts payable by the Borrower in connection with the termination of the Existing Credit Agreement. Delivery of an executed counterpart of a signature page of this Agreement by facsimile or in electronic format (e.g., “pdf” or “tif” file format) shall be effective as delivery of a manually executed counterpart of this Agreement.

ARTICLE XV

CHOICE OF LAW; CONSENT TO JURISDICTION; WAIVER OF JURY TRIAL

15.1 CHOICE OF LAW . THE RIGHTS AND DUTIES OF THE BORROWER, THE ADMINISTRATIVE AGENT AND THE LENDERS UNDER THIS AGREEMENT AND THE NOTES (INCLUDING MATTERS RELATING TO THE MAXIMUM PERMISSIBLE RATE), AND THE OTHER LOAN DOCUMENTS SHALL, PURSUANT TO NEW YORK GENERAL OBLIGATIONS LAW SECTION 5-1401, BE GOVERNED BY THE LAW OF THE STATE OF NEW YORK.

15.2 Consent To Jurisdiction . Any judicial proceeding brought against the Borrower with respect to any Loan Document Related Claim may be brought in any court of competent jurisdiction in The City of New York, and, by execution and delivery of this Agreement, the Borrower (a) accepts, generally and unconditionally, the exclusive jurisdiction of such courts and any related appellate court and irrevocably agrees to be bound by any judgment rendered thereby in connection with any Loan Document Related Claim and (b) irrevocably waives any objection it may now or hereafter have as to the venue of any such proceeding brought in such a court or that such a court is an inconvenient forum. The Borrower hereby waives personal service of process and consents that service of process upon it may be made by certified or registered mail, return receipt requested, at its address specified or determined in accordance with the provisions of Article XIII , and service so made shall be deemed completed on the third Business Day after such service is deposited in the mail. Nothing herein shall affect the right of the Administrative Agent, any Lender or any other Indemnified Person to serve process in any other manner permitted by law or shall limit the right of the Administrative Agent, the Syndication Agent, any Documentation Agent, any Lender or any other Indemnified Person to bring proceedings against the Borrower in the courts of any other jurisdiction. Any judicial proceeding by the Borrower against the Administrative Agent or any Lender involving any Loan Document Related Claim shall be brought only in a court located in the City and State of New York.

15.3 WAIVER OF JURY TRIAL . THE BORROWER, THE ADMINISTRATIVE AGENT AND EACH LENDER HEREBY WAIVE TRIAL BY JURY IN ANY JUDICIAL PROCEEDING INVOLVING ANY LOAN DOCUMENT RELATED CLAIM.

15.4 LIMITATION ON LIABILITY . TO THE EXTENT PERMITTED UNDER APPLICABLE LAW, NEITHER THE ADMINISTRATIVE AGENT, NOR THE LENDERS NOR ANY OTHER INDEMNIFIED PERSON SHALL HAVE ANY LIABILITY WITH RESPECT TO, AND THE BORROWER HEREBY WAIVES, RELEASES AND AGREES NOT TO SUE FOR, ANY SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES, AND TO THE EXTENT PERMITTED UNDER APPLICABLE LAW, PUNITIVE DAMAGES SUFFERED BY THE BORROWER IN CONNECTION WITH ANY LOAN DOCUMENT RELATED CLAIM.

15.5 USA PATRIOT ACT NOTICE . Each Lender and the Administrative Agent (for itself and not on behalf of any Lender) hereby notifies the Borrower that pursuant to the requirements of the USA Patriot Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)) (the " Patriot Act "), it is required to obtain, verify and record information that identifies the Borrower, which information includes the name and address of the Borrower and other information that will allow such Lender or Administrative Agent, as applicable, to identify the Borrower in accordance with the Patriot Act.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the Borrower, the Lenders and the Administrative Agent have executed this Agreement as of the date first above written.

WGL HOLDINGS, INC.

By: /s/ Anthony M. Nee
Anthony M. Nee
Treasurer

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent **,** Issuing Bank, Swingline Lender and Lender

By: /s/ Allison Newman
Allison Newman
Director

THE BANK OF TOKYO-MITSUBISHI UFJ, LTD. , as Syndication Agent and Lender

By: /s/ Nicholas R. Battista
Nicholas R. Battista
Director

BRANCH BANKING AND TRUST COMPANY , as Co-Documentation Agent, Issuing Bank and Lender

By: /s/ Michael F. Skorich
Michael F. Skorich
Senior Vice President

TD BANK, N.A ., as Co-Documentation Agent and Lender

By: /s/ Vijay Prasad
Vijay Prasad
Senior Vice President

THE BANK OF NEW YORK MELLON, as Lender

By: /s/ Richard K. Fronapfel
Richard K. Fronapfel
Vice President

PNC BANK, NATIONAL ASSOCIATION, as Lender

By: /s/ Bremmer Kneib
Bremmer Kneib
Vice President

U.S. BANK, NATIONAL ASSOCIATION, as Lender

By: /s/ Holland H. Williams
Holland H. Williams
AVP

CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK AGENCY, as Lender

By: /s/ Robert W. Casey, Jr.
Robert W. Casey, Jr.
Executive Director

Robert Casey
Canadian Imperial Bank of Commerce
New York Agency
Authorized Signatory

CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK AGENCY, as Lender

By: /s/ Eoin Roche
Eoin Roche
Executive Director

Eoin Roche
Canadian Imperial Bank of Commerce
New York Agency
Authorized Signatory

THE NORTHERN TRUST COMPANY, as Lender

By: /s/ Lisa Decristofaro
Lisa Decristofaro
Vice President

MECHANICS AND FARMERS BANK, as Lender

By: /s/ James E. Sansom
James E. Sansom
SVP

Exhibit 10.2

Execution Version

Published Deal CUSIP: 938836AC7
Published Revolving Facility CUSIP: 938836AD5

CREDIT AGREEMENT

DATED AS OF APRIL 3, 2012

AMONG

WASHINGTON GAS LIGHT COMPANY,

THE LENDERS PARTIES HERETO,

WELLS FARGO BANK, NATIONAL ASSOCIATION,
AS ADMINISTRATIVE AGENT,

THE BANK OF TOKYO-MITSUBISHI UFJ, LTD.,
AS SYNDICATION AGENT,

BRANCH BANKING AND TRUST COMPANY AND
TD BANK, N.A.
AS DOCUMENTATION AGENTS,

AND

WELLS FARGO SECURITIES, LLC,
THE BANK OF TOKYO-MITSUBISHI UFJ, LTD.,
BB&T CAPITAL MARKETS AND
TD BANK, N.A.
AS JOINT LEAD ARRANGERS AND JOINT BOOK RUNNERS

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CREDIT AGREEMENT, dated as of April 3, 2012 (the " Agreement "), among WASHINGTON GAS LIGHT COMPANY, as Borrower, the financial institutions from time to time parties hereto, as LENDERS, WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent, THE BANK OF TOKYO-MITSUBISHI UFJ, LTD., as Syndication Agent, and BRANCH BANKING AND TRUST COMPANY and THE TORONTO-DOMINION BANK, as Documentation Agents.

RECITALS

WHEREAS, the Borrower has requested that the Lenders provide a revolving credit facility, and the Lenders are willing to do so on the terms and conditions set forth herein.

NOW, THEREFORE, the parties hereto agree as follows:

ARTICLE I
INTERPRETATION

1.1 Definitions . As used in this Agreement:

" Acquisition " means any transaction, or any series of related transactions, consummated on or after the Agreement Date, by which the Borrower or any of its Subsidiaries (i) acquires any going business or all or substantially all of the assets of any firm, corporation or limited liability company, or division thereof, whether through purchase of assets, merger or otherwise, or (ii) directly or indirectly acquires (in one transaction or as the most recent transaction in a series of transactions) at least a majority (in number of votes) of the securities of a corporation which have ordinary voting power for the election of directors (other than securities having such power only by reason of the happening of a contingency) or a majority (by percentage or voting power) of the outstanding ownership interests of a partnership or limited liability company.

" Active Arrangers Fee Letter " means the letter to the Borrower from Wells Fargo Securities and BTMU, dated as of February 15, 2012.

" Additional Commitment Lender " is defined in Section 2.5.2 .

" Administrative Agent " means Wells Fargo Bank, National Association, in its capacity as administrative agent for the Lenders pursuant to Article X , and not in its individual capacity as a Lender or any successor Administrative Agent appointed pursuant to Article X .

" Administrative Questionnaire " means an Administrative Questionnaire in a form supplied by the Administrative Agent.

" Administrative Fee Letter " means the letter to the Borrower from Wells Fargo dated as of February 15, 2012.

" Affiliate " of any Person means any other Person directly or indirectly controlling, controlled by or under common control with such Person. A Person shall be deemed to control another Person if the controlling Person owns 10% or more of any class of voting securities (or other ownership interests) of the controlled Person or possesses, directly or indirectly, the power to direct or cause the direction of the management or policies of the controlled Person, whether through ownership of stock, by contract or otherwise.

"Aggregate Commitments" means the aggregate of the Commitments of all the Lenders, in the initial aggregate amount of $350,000,000, as increased or decreased from time to time pursuant to the terms hereof.

"Agreement" means this Agreement, including all schedules, annexes and exhibits hereto.

"Agreement Date" means the first date all the conditions precedent set forth in Sections 4.1 and 4.2 shall have been satisfied or waived in accordance with the terms of this Agreement, which is April 3, 2012.

"Alternate Base Rate" means, for any day, a fluctuating rate per annum equal to the highest of (i) the Prime Rate for such day, (ii) the Federal Funds Effective Rate for such day plus 0.50%, and (iii) the LIBOR Rate plus 1.00%.

"Applicable Law" means, anything in Section 15.1 to the contrary notwithstanding, (i) all applicable common law and principles of equity and (ii) all applicable provisions of all (A) treaties, constitutions, statutes, rules, regulations, guidelines and orders of governmental bodies, including the interpretation or administration thereof by any Governmental Authority charged with the enforcement, interpretation or administration thereof, (B) Governmental Approvals and (C) orders, decisions, judgments and decrees.

"Applicable Margin" means, with respect to Loans of any Type at any time, the percentage rate per annum which is applicable at such time with respect to Loans of such Type as set forth in the Pricing Schedule.

"Applicable Percentage" means, with respect to any Lender at any time, the percentage of the Aggregate Commitments represented by such Lender's Commitment at such time, subject to adjustment as provided in Section 2.22. If the commitment of each Lender to make Loans and the obligation of the Issuing Banks to issue Letters of Credit have been terminated pursuant to Section 8.1, or if the Aggregate Commitments have expired, then the Applicable Percentage of each Lender shall be determined based on the Applicable Percentage of such Lender most recently in effect, giving effect to any subsequent assignments.

"Arrangers" means Wells Fargo Securities, BTMU, BB&TCM and TD, each in its capacity as a joint lead arranger and bookrunner.

"Authorized Officer" means any of the Vice President and Chief Financial Officer, Vice President and General Counsel, or the Treasurer of the Borrower, acting singly.

"Bankruptcy Code" means the United States Bankruptcy Code (11 U.S.C. §101 et seq.).

"Base Rate Loan" means a Loan which, except as otherwise provided in Section 2.8, bears interest at the Alternate Base Rate plus the Applicable Margin.

" BB&T " means Branch Banking and Trust Company, and its successors.

" BB&TCM " means BB&T Capital Markets, and its successors.

" Borrower " means Washington Gas Light Company, a Virginia and District of Columbia corporation.

" Borrowing Date " means a date on which a Loan is made.

" Borrowing Notice " is defined in Section 2.2.2 .

" BTMU " means The Bank of Tokyo-Mitsubishi UFJ Ltd., and its successors.

" Business Day " means (i) any day other than a Saturday or Sunday, a legal holiday, or a day on which commercial banks in Charlotte, North Carolina or New York, New York are authorized or required by law to be closed and (ii) in respect of any LIBOR determination, any such day that is also a day on which trading in Dollar deposits is conducted by banks in London, England in the London interbank eurodollar market.

" Capitalized Lease " of a Person means any lease of Property by such Person as lessee which would be capitalized on a balance sheet of such Person prepared in accordance with GAAP.

" Capitalized Lease Obligations " of a Person means the amount of the obligations of such Person under Capitalized Leases which would be shown as a liability on a balance sheet of such Person prepared in accordance with GAAP.

" Cash Collateral Account " has the meaning given to such term in Section 3.8 .

" Cash Collateralize " means to pledge and deposit with or deliver to the Administrative Agent, for the benefit of the Administrative Agent, the Issuing Banks and the Lenders, as collateral for the Letter of Credit Exposure or obligations of Lenders to fund participations in respect of Letter of Credit Exposure, cash or deposit account balances or, if the Administrative Agent and the Issuing Banks shall agree in their sole discretion, other credit support, in each case pursuant to documentation in form and substance satisfactory to the Administrative Agent and the Issuing Banks. " Cash Collateral " shall have a meaning correlative to the foregoing and shall include the proceeds of such cash collateral and other credit support.

" Cash Equivalents " means (i) short-term obligations of, or fully guaranteed by, the United States of America, (ii) commercial paper rated A-1 or better by S&P or Fitch or P-1 or better by Moody's, (iii) demand deposit accounts maintained in the ordinary course of business, and (iv) certificates of deposit issued by, and time deposits with, commercial banks (whether domestic or foreign) having capital and surplus in excess of $100,000,000; provided in each case that the same provides for payment of both principal and interest (and not principal alone or interest alone) and is not subject to any contingency regarding the payment of principal or interest.

" CERCLA " means the Comprehensive Environmental Response, Compensation and Liability Act of 1980.

" CERCLIS " means the Comprehensive Environmental Response, Compensation, and Liability Information System List.

" Change in Law " means the occurrence, after the date of this Agreement, of any of the following: (i) the adoption or taking effect of any law, rule, regulation or treaty, (ii) any change in any law, rule, regulation or treaty or in the administration, interpretation, implementation or application thereof by any Governmental Authority or (iii) the making or issuance of any request, rule, guideline or directive (whether or not having the force of law) by any Governmental Authority; provided that notwithstanding anything herein to the contrary, (x) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives thereunder or issued in connection therewith and (y) all requests, rules, guidelines or directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or the United States or foreign regulatory authorities, in each case pursuant to Basel III, shall in each case be deemed to be a "Change in Law", regardless of the date enacted, adopted or issued.

" Change in Control " means (i) an event or series of events by which any "person" or "group" (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any employee benefit plan of such person or its Subsidiaries, and any person or entity acting in its capacity as trustee, agent or other fiduciary or administrator of any such plan) becomes the "beneficial owner" (as defined in Rules 13d-3 and 13d-5 under the Exchange Act, except that a "person" or "group" shall be deemed to have "beneficial ownership" of all capital stock that such "person" or "group" has the right to acquire, whether such right is exercisable immediately or only after the passage of time (such right, an "option right")), directly or indirectly, of more than thirty percent (30%) of the capital stock of the Parent entitled to vote in the election of members of the board of directors (or equivalent governing body) of the Parent, (ii) a majority of the members of the board of directors (or other equivalent governing body) of the Parent shall not constitute Continuing Directors, or (iii) the Parent has ceased to own 100% of common stock of the Borrower and 99% of all issued and outstanding stock of the Borrower.

" Code " means the Internal Revenue Code of 1986.

" Commitment " means, for each Lender, the obligation of such Lender to make Loans not exceeding the amount set forth opposite such Lenders name on Schedule 1.1-B , as it may be modified as a result of any assignment that has become effective pursuant to Section 12.3.2 or as otherwise decreased or increased from time to time pursuant to the terms hereof.

" Commitment Increase " is defined in Section 2.5.2 .

" Commitment Increase Supplement " is defined in Section 2.5.2 .

" Compliance Certificate " is defined in Section 4.2 .

" Connection Income Taxes " means Other Connection Taxes that are imposed on or measured by net income (however denominated) or that are franchise Taxes or branch profits Taxes.

" Consolidated Financial Indebtedness " means at any time the Financial Indebtedness of the Borrower and its Subsidiaries calculated on a consolidated basis as of such time.

" Consolidated Net Worth " means at any time the sum of common shareholders' equity of the Borrower and preferred stock of the Borrower, as reported on the consolidated balance sheet of the Borrower prepared as of such time.

" Consolidated Total Capitalization " means at any time the sum of Consolidated Financial Indebtedness and Consolidated Net Worth, each calculated at such time.

" Contingent Obligation " of a Person means any agreement, Contract, undertaking or arrangement by which such Person assumes, guarantees, endorses, contingently agrees to purchase or provide funds for the payment of, or otherwise becomes or is contingently liable upon, the obligation or liability of any other Person, or agrees to maintain the net worth or working capital or other financial condition of any other Person, or otherwise assures any creditor of such other Person against loss, including, without limitation, any comfort letter, operating agreement, take or pay contract or the obligations of any such Person as general partner of a partnership with respect to the liabilities of the partnership.

" Continuing Directors " shall mean the directors of the Parent or the Borrower on the Agreement Date and each other director of the Parent or the Borrower, if, in each case, such other director's nomination for election to the board of directors (or equivalent governing body) of the Parent or the Borrower is recommended by at least 51% of the then Continuing Directors.

" Contract " means (i) any agreement, including an indenture, lease or license, (ii) any deed or other instrument of conveyance, (iii) any certificate of incorporation or charter and (iv) any by-law.

" Controlled Group " means all members of a controlled group of corporations and all members of a group of trades or businesses (whether or not incorporated) under common control, which together with the Borrower are treated as a single employer under Section 414(b) or 414(c) of the Code or Section 4001 of ERISA.

" Conversion/Continuation Notice " is defined in Section 2.2.7 .

" Credit Exposure " means, with respect to any Lender at any time, the sum of (i) the aggregate principal amount of all Loans made by such Lender that are outstanding at such time, (ii) such Lender's Swingline Exposure at such time and (iii) such Lender's Letter of Credit Exposure at such time.

" Defaulting Lender " means, subject to Section 2.22.2 any Lender that (i) has failed to (x) fund all or any portion of its Loans within two Business Days of the date such Loans were required to be funded hereunder unless such Lender notifies the Administrative Agent and the Borrower in writing that such failure is the result of such Lender's determination that one or more conditions precedent to funding (each of which conditions precedent, together with any applicable default, shall be specifically identified in such writing) has not been satisfied, or (y) pay to the Administrative Agent, any Issuing Bank, any Swingline Lender or any other Lender any other amount required to be paid by it hereunder (including in respect of its participation in Letters of Credit or Swingline Loans) within two Business Days of the date when due, (ii) has notified the Borrower, the Administrative Agent or any Issuing Bank or Swingline Lender in writing that it does not intend to comply with its funding obligations hereunder, or has made a public statement to that effect (unless such writing or public statement relates to such Lender's obligation to fund a Loan hereunder and states that such position is based on such Lender's determination that a condition precedent to funding (which condition precedent, together with any applicable default, shall be specifically identified in such writing or public statement) cannot be satisfied), (iii) has failed, within three Business Days after written request by the Administrative Agent or the Borrower, to confirm in writing to the Administrative Agent and the Borrower that it will comply with its prospective funding obligations hereunder (provided that such Lender shall cease to be a Defaulting Lender pursuant to this clause (iii) upon receipt of such written confirmation by the Administrative Agent and the Borrower), or (iv) has, or has a direct or indirect parent company that has, (x) become the subject of a proceeding under the Bankruptcy Code or under other applicable bankruptcy, insolvency or similar law now or hereafter in effect, or (y) had appointed for it a receiver, custodian, conservator, trustee, administrator, assignee for the benefit of creditors or similar Person charged with reorganization or liquidation of its business or assets, including the Federal Deposit Insurance Corporation or any other state or federal regulatory authority acting in such a capacity; provided that a Lender shall not be a Defaulting Lender solely by virtue of the ownership or acquisition of any equity interest in that Lender or any direct or indirect parent company thereof by a Governmental Authority so long as such ownership interest does not result in or provide such Lender with immunity from the jurisdiction of courts within the United States or from the enforcement of judgments or writs of attachment on its assets or permit such Lender (or such Governmental Authority) to reject, repudiate, disavow or disaffirm any contracts or agreements made with such Lender. Any determination by the Administrative Agent that a Lender is a Defaulting Lender under any one or more of clauses (i) through (iv) above shall be conclusive and binding absent manifest error, and such Lender shall be deemed to be a Defaulting Lender (subject to Section 2.22.2) upon delivery of written notice of such determination by the Administrative Agent to the Borrower, the Issuing Bank, the Swingline Lender and each Lender.

" Documentation Agent " means each of BB&T and TD, acting in the capacity as documentation agent hereunder.

" Dollars " and the sign " $ " mean lawful money of the United States of America.

" Eligible Assignee " means any Lender, Affiliate of a Lender or other Person that meets the requirements to be an assignee under Section 12.3.1 .

" Employee Benefit Plans " is defined in Section 5.8 .

" Environmental Laws " means any and all federal, state, local and foreign statutes, Applicable Laws, judicial decisions, regulations, ordinances, rules, judgments, orders, decrees, plans, injunctions, permits, concessions, grants, franchises, licenses, agreements and other governmental restrictions relating to (i) the protection of the environment, (ii) the effect of the environment on human health, (iii) emissions, discharges or releases of pollutants, contaminants, hazardous substances or wastes into ambient air, surface water, ground water, land surface or subsurface strata, or (iv) the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of pollutants, contaminants, hazardous substances or wastes or the clean-up or other remediation thereof.

" ERISA " means the Employee Retirement Income Security Act of 1974.

" Event of Default " means an event described in Article VII .

" Exchange Act " means Securities Exchange Act of 1934.

" Excluded Taxes " means any of the following Taxes imposed on or with respect to a Recipient or required to be withheld or deducted from a payment to a Recipient, (i) Taxes imposed on or measured by net income (however denominated), franchise Taxes, and branch profits Taxes, in each case, (x) imposed as a result of such Recipient being organized under the laws of, or having its principal office or, in the case of any Lender, its Lending Installation located in, the jurisdiction imposing such Tax (or any political subdivision thereof) or (y) that are Other Connection Taxes, (ii) in the case of a Lender, U.S. federal withholding Taxes imposed on amounts payable to or for the account of such Lender with respect to an applicable interest in a Loan or Commitment pursuant to a law in effect on the date on which (x) such Lender acquires such interest in the Loan or Commitment (other than pursuant to an assignment request by the Borrower under Section 2.21) or (y) such Lender changes its Lending Installation, except in each case to the extent that, pursuant to Section 2.19 , amounts with respect to such Taxes were payable either to such Lender's assignor immediately before such Lender became a party hereto or to such Lender immediately before it changed its Lending Installation, (iii) Taxes attributable to such Recipient's failure to comply with Section 2.19.7 and (iv) any U.S. federal withholding Taxes imposed under FATCA.

" Existing Credit Agreement " means that certain Amended and Restated Credit Agreement dated as of August 3, 2007, among the Borrower, the several lender parties listed on the signature pages thereof, Wachovia Bank, National Association, as administrative agent, Bank of Tokyo-Mitsubishi UFJ Trust Company, as syndication agent, and SunTrust Bank and Citibank, N.A., as documentation agents.

" Extension Option " means the option of the Borrower under Section 2.6 hereof to extend the Facility Termination Date.

" Facility Fee " is defined in Section 2.4.2 .

" Facility Fee Rate " means, at any time, the percentage rate per annum at which Facility Fees are accruing on the Aggregate Commitments (without regard to usage) at such time as set forth in the Pricing Schedule.

" Facility Termination Date " means September 30, 2012, provided that upon the delivery of certified resolutions of the Board of Directors of the Borrower, reasonably satisfactory to the Administrative Agent, authorizing the Borrower's performance of its obligations under the Loan Documents through the fifth anniversary of the Agreement Date, the fifth anniversary of the Agreement Date (as such date may be extended from time to time pursuant to Section 2.6).

"FATCA" means Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended version that is substantively comparable) and any current or future regulations or official interpretations thereof.

"Federal Funds Effective Rate" means, for any day, an interest rate per annum equal to the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System arranged by Federal funds brokers on such day, as published for such day (or, if such day is not a Business Day, for the immediately preceding Business Day) by the Federal Reserve Bank of New York, or, if such rate is not so published for any day which is a Business Day, the average of the quotations at approximately 10:00 a.m. on such day on such transactions received by the Administrative Agent from three Federal funds brokers of recognized standing selected by the Administrative Agent in its sole discretion.

"Fee Letters" means, collectively, the Active Arrangers Fee Letter, Passive Arrangers Fee Letter and Administrative Fee Letter.

"Financial Indebtedness" of a Person means such Person's (i) obligations for borrowed money which, in accordance with GAAP, would be shown as short-term debt on a consolidated balance sheet of such Person, including obligations under notes, commercial paper, acceptances and other short-term instruments, and (ii) obligations for borrowed money which, in accordance with GAAP, would be shown as long-term debt (including current maturities) on a consolidated balance sheet of such Person.

"Fitch" means Fitch Ratings, Ltd.

"Foreign Lender" means (i) if the Borrower is a U.S. Person, a Lender that is not a U.S. Person, and (ii) if the Borrower is not a U.S. Person, a Lender that is resident or organized under the laws of a jurisdiction other than that in which the Borrower is resident for tax purposes.

"Fronting Exposure" means, at any time there is a Defaulting Lender, (i) with respect to any Issuing Bank, such Defaulting Lender's Letter of Credit Exposure with respect to Letters of Credit issued by such Issuing Bank other than such portion of such Defaulting Lender's Letter of Credit Exposure as to which such Defaulting Lender's participation obligation has been reallocated to other Lenders or Cash Collateralized in accordance with the terms hereof, and (ii) with respect to any Swingline Lender, such Defaulting Lender's Swingline Exposure with respect to outstanding Swingline Loans made by the Swingline Lender other than Swingline Loans as to which such Defaulting Lender's participation obligation has been reallocated to other Lenders in accordance with the terms hereof.

"GAAP" means generally accepted accounting principles in the United States of America, as set forth in the statements, opinions and pronouncements of the Accounting Principles Board, the American Institute of Certified Public Accountants and the Financial Accounting Standards Board, consistently applied and maintained, as in effect from time to time (subject to the provisions of Section 1.2).

“ Governmental Approval ” means any authority, consent, approval, license (or the like) or exemption (or the like) of any governmental unit.

“ Governmental Authority ” means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supranational bodies such as the European Union or the European Central Bank).

“ Hazardous Material ” means: any “hazardous substance”, as defined by CERCLA; any petroleum product; or any pollutant or contaminant or hazardous, dangerous or toxic chemical, material or substance within the meaning of any other Environmental Law.

“ Hedge Agreement ” means any interest or foreign currency rate swap, cap, collar, option, hedge, forward rate or other similar agreement or arrangement designed to protect against fluctuations in interest rates, currency exchange rates or spot prices of new materials.

“ Indebtedness ” of a Person means such Person’s (i) obligations for borrowed money, (ii) obligations representing the deferred purchase price of Property or services (other than accounts payable arising in the ordinary course of such Person’s business payable on terms customary in the trade, (iii) obligations, whether or not assumed, secured by Liens on, or payable out of the proceeds or production from, Property now or hereafter owned or acquired by such Person, (iv) obligations which are evidenced by bonds, debentures, notes, acceptances, or other instruments, (v) obligations of such Person to purchase securities or other Property arising out of or in connection with the sale of the same or substantially similar securities or Property, (vi) Capitalized Lease Obligations, (vii) any other obligation for borrowed money or other financial accommodation which in accordance with GAAP would be shown as a liability on the consolidated balance sheet of such Person, (viii) Contingent Obligations in respect of any type of obligation described in any of the other clauses of this definition, (ix) obligations in respect letters of credit (including standby and commercial), bankers’ acceptances, bank guaranties, surety bonds and similar instruments, (x) for all purposes other than Section 6.6 , net obligations under any Hedge Agreements, (xi) Operating Lease Obligations, (xii) obligations in respect of Sale and Leaseback Transactions and (xiii) Off-Balance Sheet Liabilities. Permitted Commodity Hedging Obligations shall not constitute Indebtedness for purposes of this Agreement.

“ Indemnified Person ” means any Person that is, or at any time was, the Administrative Agent, the Syndication Agent, a Documentation Agent, a Lender or an Arranger or an Affiliate, director, officer, employee or agent of any such Person.

“ Indemnified Taxes ” means (i) Taxes, other than Excluded Taxes, imposed on or with respect to any payment made by or on account of any obligation of the Borrower under any Loan Document and (ii) to the extent not otherwise described in clause (i), Other Taxes.

“ Indemnitee ” is defined in Section 9.6.2 .

“ Interest Period ” means, with respect to a LIBOR Rate Loan, the period commencing on the date such LIBOR Rate Loan is disbursed or converted to or continued as a LIBOR Rate Loan and ending on the date one, two, three or six months thereafter, as selected by the Borrower pursuant to this Agreement; provided , that (i) any Interest Period pertaining to a LIBOR Rate Loan that begins on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the calendar month at the end of such Interest Period) shall end on the last Business Day of the calendar month at the end of such Interest Period, (ii) any Interest Period that would otherwise end on a day that is not a Business Day shall be extended to the next succeeding Business Day unless such Business Day falls in another calendar month, in which case such Interest Period shall end on the next preceding Business Day; and (iii) no Interest Period shall extend beyond the Facility Termination Date.

" Issuing Bank " means each of Wells Fargo and BB&T, in their respective capacities as issuers of Letters of Credit under this Agreement.

" LC Fee " is defined in Section 2.4.4 .

" Lenders " means the lending institutions listed on the signature pages of this Agreement, any Additional Commitment Lenders, and their respective successors and assigns.

" Lending Installation " means, with respect to a Lender or the Administrative Agent, the office, branch, subsidiary or affiliate of such Lender or the Administrative Agent designated on its Administrative Questionnaire or otherwise selected by such Lender or the Administrative Agent pursuant to Section 2.15 .

" Letter of Credit Exposure " means, with respect to any Lender at any time, such Lender's ratable share (based on the proportion that its Commitment bears to the Aggregate Commitments at such time) of the sum of (i) the aggregate Stated Amount of all Letters of Credit outstanding at such time and (ii) the aggregate amount of all Reimbursement Obligations outstanding at such time.

" Letter of Credit Maturity Date " means the fifth Business Day prior to the Facility Termination Date.

" Letter of Credit Notice " has the meaning given to such term in Section 3.2 .

" Letter of Credit Subcommitment " means $35,000,000 or, if less, the Aggregate Commitments at the time of determination, as such amount may be reduced at or prior to such time pursuant to the terms hereof.

" Letters of Credit " is defined in Section 3.1 .

" LIBOR Market Index Rate " means, for any day, an interest rate per annum for one month Dollar deposits as reported on Reuters Screen LIBOR01 Page (or any successor page), on such day, or if such day is not a Business Day, then the immediately preceding Business Day (or if not so reported, then as determined by the Administrative Agent from another recognized source or interbank quotation).

" LIBOR Market Index Rate Loan " means a Loan that bears interest at the LIBOR Market Index Rate plus the Applicable Margin.

" LIBOR Rate " means:

(a) with respect to each LIBOR Rate Loan comprising part of the same borrowing for any Interest Period, an interest rate per annum obtained by dividing (i) (y) the rate of interest appearing on Reuters Screen LIBOR01 Page (or any successor page) that represents an average British Bankers Association Interest Settlement Rate for Dollar deposits (" BBA LIBOR ") or (z) if such rate is not available at such time for any reason, the rate per annum determined by the Administrative Agent to be the rate at which deposits in Dollars for delivery on the first day of such Interest Period in same day funds in the approximate amount of the LIBOR Rate Loan being made, continued or converted and with a term equivalent to such Interest Period would be offered by Wells Fargo's London Branch to major banks in the London interbank eurodollar market at their request at approximately 11:00 a.m., London time, two Business Days prior to the first day of such Interest Period, by (ii) the amount equal to 1.00 minus the Reserve Requirement (expressed as a decimal) for such Interest Period.

(b) for any interest calculation with respect to a Base Rate Loan on any date, the rate per annum equal to (i) BBA LIBOR, at approximately 11:00 a.m., London time determined two Business Days prior to such date for Dollar deposits being delivered in the London interbank market for a term of one month commencing that day or (ii) if such published rate is not available at such time for any reason, the rate per annum determined by the Administrative Agent to be the rate at which deposits in Dollars for delivery on the date of determination in same day funds in the approximate amount of the Base Rate Loan being made or maintained and with a term equal to one month would be offered by Wells Fargo's London Branch to major banks in the London interbank eurodollar market at their request at the date and time of determination.

" LIBOR Rate Loan " means a Loan which bears interest at the LIBOR Rate plus the Applicable Margin requested by the Borrower pursuant to Section 2.2 .

" Lien " means any lien (statutory or other), mortgage, pledge, hypothecation, assignment, deposit arrangement, encumbrance or preference, priority or other security agreement or preferential arrangement of any kind or nature whatsoever (including, without limitation, the interest of a vendor or lessor under any conditional sale, Capitalized Lease or other title retention agreement).

" Loan " means, with respect to a Lender, any Revolving Loan or Swingline Loan made by such Lender pursuant to Article II (and, in the case of a loan made pursuant to Section 2.2.2 , any conversion or continuation thereof).

" Loan Document Related Claim " means any claim or dispute (whether arising under Applicable Law, including any "environmental" or similar law, under Contract or otherwise and, in the case of any proceeding relating to any such claim or dispute, whether civil, criminal, administrative or otherwise) in any way arising out of, related to, or connected with, the Loan Documents, the relationships established thereunder or any actions or conduct thereunder or with respect thereto, whether such claim or dispute arises or is asserted before or after the Agreement Date or before or after the Repayment Date.

" Loan Documents " means this Agreement and any Notes issued pursuant to Section 2.11 , the Fee Letters, and all other agreements, instruments, documents and certificates now or hereafter executed and delivered to the Administrative Agent or any Lender by or on behalf of the Borrower with respect to this Agreement, in each case as amended, modified, supplemented or restated from time to time.

" Material Adverse Effect " means any effect, resulting from any event or circumstance whatsoever, which will, or is reasonably likely to, have a material adverse effect on the financial condition, operations, assets, business, properties or prospects of the Borrower and its Subsidiaries, taken as a whole, on the ability of the Borrower to perform its obligations under this Agreement, or on the validity or enforceability of this Agreement.

" Material Subsidiary " means at any time with respect to a Person, a Subsidiary, if any, of such Person, the consolidated assets of which exceed at such time 15% of the consolidated assets of such Person and its Subsidiaries, if any, determined on a consolidated basis.

" Maximum Permissible Rate " means, with respect to interest payable on any amount, the rate of interest on such amount that, if exceeded, could, under Applicable Law, result in (i) civil or criminal penalties being imposed on the payee or (ii) the payee's being unable to enforce payment of (or, if collected, to retain) all or any part of such amount or the interest payable thereon.

" Moody's " means Moody's Investors Service, Inc.

" Multiemployer Plan " means any "multiemployer plan" within the meaning of Section 4001(a)(3) of ERISA to which the Borrower or any member of the Controlled Group is making or is obligated to make contributions or has made or been obligated to make contributions.

" Non-Consenting Lender " means a Lender that does not approve any consent, waiver or amendment to any Loan Document that (i) requires the approval of all Lenders (or all Lenders directly affected thereby) under Section 8.2 and (ii) has been approved by the Required Lenders.

" Notes " means, collectively, all of the Revolving Notes and all of the Swingline Notes that may be issued hereunder, and " Note " means any one of the Notes.

" Obligations " means all principal of and interest (including interest accruing after the filing of a petition or commencement of a case by or with respect to the Borrower seeking relief under any applicable federal and state laws pertaining to bankruptcy, reorganization, arrangement, moratorium, readjustment of debts, dissolution, liquidation or other debtor relief, specifically including, without limitation, the Bankruptcy Code and any fraudulent transfer and fraudulent conveyance laws, whether or not the claim for such interest is allowed in such proceeding) on the Loans and Reimbursement Obligations and all fees, expenses, indemnities and other obligations owing, due or payable at any time by the Borrower or any Subsidiary of the Borrower to the Administrative Agent, any Lender, the Swingline Lender, the Issuing Bank or any other Person entitled thereto, under this Agreement or any of the Loan Documents, in each case whether direct or indirect, joint or several, absolute or contingent, matured or unmatured, liquidated or unliquidated, secured or unsecured, and whether existing by contract, operation of law or otherwise.

" OFAC " means the U.S. Department of the Treasury's Office of Foreign Assets Control, and any successor thereto.

" Other Connection Taxes " means, with respect to any Recipient, Taxes imposed as a result of a present or former connection between such Recipient and the jurisdiction imposing such Tax (other than connections arising from such Recipient having executed, delivered, become a party to, performed its obligations under, received payments under, received or perfected a security interest under, engaged in any other transaction pursuant to or enforced any Loan Document, or sold or assigned an interest in any Loan or Loan Document).

" Off-Balance Sheet Liability " of a Person means (i) any repurchase obligation or liability of such Person with respect to accounts or notes receivable sold by such Person, (ii) any liability under any Sale and Leaseback Transaction which is not a Capitalized Lease, (iii) any liability under any so-called "synthetic lease" transaction entered into by such Person, or (iv) any obligation arising with respect to any other transaction which is the functional equivalent of, or takes the place of, borrowing, but which does not constitute a liability on the balance sheets of such Person, but excluding from this clause (iv) Operating Leases.

" Operating Lease " of a Person means any lease of Property (other than a Capitalized Lease) by such Person as lessee which has an original term (including any required renewals and any renewals effective at the option of the lessor) of one year or more.

" Operating Lease Obligations " means, as at any date of determination, the amount obtained by aggregating the present values, determined in the case of each particular Operating Lease by applying a discount rate (which discount rate shall equal the discount rate which would be applied under GAAP if such Operating Lease were a Capitalized Lease) from the date on which each fixed lease payment is due under such Operating Lease to such date of determination, of all fixed lease payments due under all Operating Leases of the Borrower and its Subsidiaries.

" Other Taxes " means all present or future stamp, court or documentary, intangible, recording, filing or similar Taxes that arise from any payment made under, from the execution, delivery, performance, enforcement or registration of, from the receipt or perfection of a security interest under, or otherwise with respect to, any Loan Document, except any such Taxes that are Other Connection Taxes imposed with respect to an assignment (other than an assignment made pursuant to Section 2.21.1).

" Overdue Rate " means (i) in the case of overdue amounts of the principal of a LIBOR Rate Loan, (A) until the last day of the applicable Interest Period during which such Loan became due and payable, the rate otherwise applicable hereunder plus the Applicable Margin plus 2%, and (B) thereafter, the Alternate Base Rate in effect from time to time plus the Applicable Margin plus 2%, and (ii) in the case of all other overdue amounts, the Alternate Base Rate in effect from time to time plus the Applicable Margin plus 2%.

" Parent " means WGL Holdings, Inc., a Virginia and District of Columbia corporation.

" Participants " is defined in Section 12.2.1 .

" Participant Register " has the meaning given to such term in Section 12.2.1 .

“ Passive Arrangers Fee Letter ” means the letter to Borrower from BCM and TD dated as of February 15, 2012.

“ Patriot Act ” is defined in Section 15.5 .

“ Payment Date ” means the last day of each March, June, September and December.

“ PBGC ” means the Pension Benefit Guaranty Corporation.

“ Pension Plan ” means a “pension plan”, as such term is defined in section 3(2) of ERISA, which is subject to Title IV of ERISA, and to which the Borrower or any corporation, trade or business that is, along with the Borrower, a member of a Controlled Group, may have liability, including any liability by reason of having been a substantial employer within the meaning of section 4063 of ERISA at any time during the preceding five years, or by reason of being deemed to be a contributing sponsor under section 4069 of ERISA.

“ Permitted Commodity Hedging Obligations ” means obligations of the Borrower with respect to commodity agreements or other similar agreements or arrangements entered into in the ordinary course of business designed to protect against, or mitigate risks with respect to, fluctuations of commodity prices to which the Borrower is exposed in the conduct of its business so long as (a) the management of the Borrower has determined that entering into such agreements or arrangements are bona fide hedging activities which comply with the Borrower’s risk management policies and (b) such agreements or arrangements are not entered into for speculative purposes.

“ Person ” means any natural person, corporation, firm, joint venture, partnership, limited liability company, association, enterprise, trust or other entity or organization, or any government or political subdivision or any agency, department or instrumentality thereof.

“ Pricing Schedule ” means Schedule 1.1-A attached hereto.

“ Prime Rate ” means a rate per annum equal to the prime rate of interest announced from time to time by Wells Fargo, (which is not necessarily the lowest rate charged to any customer), changing when and as said prime rate changes.

“ Prior Termination Date ” is defined in Section 2.6.3 .

“ Property ” of a Person means any and all property, whether real, personal, tangible, intangible, or mixed, of such Person, or other assets owned, leased or operated by such Person.

“ Purchasers ” is defined in Section 12.3.1 .

“ Recipient ” means (i) the Administrative Agent, (ii) any Lender and (iii) the Issuing Bank, as applicable.

“ Refunded Swingline Loans ” is defined in Section 2.2.4 .

“ Register ” is defined in Section 12.3.4 .

“ Regulation D ” means Regulation D of the Board of Governors of the Federal Reserve System.

“ Regulation U ” means Regulation U of the Board of Governors of the Federal Reserve System.

“ Regulation X ” means Regulation X of the Board of Governors of the Federal Reserve System.

“ Reimbursement Obligation ” is defined in Section 3.4 .

“ Related Parties ” means, with respect to any Person, such Person’s Affiliates and the partners, directors, officers, employees, agents, trustees, administrators, managers, advisors and representatives of such Person and of such Person’s Affiliates.

“ Release ” means “release”, as such term is defined in CERCLA.

“ Repayment Date ” means the later of (a) the date of the termination of the Commitments (whether as a result of the occurrence of the Facility Termination Date, reduction to zero pursuant to Section 2.5.1 or termination pursuant to Article VIII), and (b) the date of the payment in full of all principal of and interest on the Loans and all other amounts payable or accrued hereunder.

“ Reportable Event ” means a reportable event, as defined in Section 4043 of ERISA and the regulations issued under such section, with respect to a Plan, excluding, however, such events as to which the PBGC has by regulation waived the requirement of Section 4043(a) of ERISA that it be notified within 30 days of the occurrence of such event; provided, however , that a failure to meet the minimum funding standard of Section 412 of the Code and of Section 302 of ERISA shall be a Reportable Event regardless of the issuance of any such waiver of the notice requirement in accordance with either Section 4043(a) of ERISA or Section 412(d) of the Code.

“ Required Lenders ” means Lenders having in the aggregate more than 50.0% of the outstanding Aggregate Commitments or, if the Aggregate Commitments have been terminated, Lenders holding in the aggregate more than 50.0% of the aggregate Credit Exposure; provided that the Commitment of, and the portion of outstanding Loans and Letters of Credit held or deemed held by, any Defaulting Lender shall be excluded for purposes or making a determination of Required Lenders.

“ Reserve Requirement ” means, with respect to any Interest Period, the reserve percentage (expressed as a decimal and rounded upwards, if necessary, to the next higher 1/100 th of 1%) in effect from time to time during such Interest Period, as provided by the Federal Reserve Board, applied for determining the maximum reserve requirements (including, without limitation, basic, supplemental, marginal and emergency reserves) applicable to Wells Fargo under Regulation D with respect to “Eurocurrency liabilities” within the meaning of Regulation D, or under any similar or successor regulation with respect to Eurocurrency liabilities or Eurocurrency funding. The LIBOR Rate shall be adjusted automatically on and as of the effective date of any change in the Reserve Requirement.

" Resignation Effective Date " is defined in Section 10.6.1 .

" Resource Conservation and Recovery Act " means the Resource Conservation and Recovery Act, 42 U.S.C. Section 690, et seq.

" Revolving Loan " is defined in Section 2.1.3 .

" Revolving Note " means a promissory note issued at the request of a Lender pursuant to Section 2.11.4, substantially in the form of Exhibit 2.11.4-A .

" S&P " means Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc.

" Sale and Leaseback Transaction " means any sale or other transfer of Property by any Person with the intent to lease such Property as lessee.

" Sanctioned Country " means a country subject to a sanctions program identified on the list maintained by OFAC and available at http://www.treas.gov/offices/enforcement/ofac/programs/ , or as otherwise published from time to time.

" Sanctioned Person " means (i) a Person named on the list of Specially Designated Nationals or Blocked Persons maintained by OFAC available at http://www.treasury.gov/resource-center/sanctions/SDN-List , or as otherwise published from time to time, or (ii) (A) an agency of the government of a Sanctioned Country, (B) an organization controlled by a Sanctioned Country, or (C) a Person resident in a Sanctioned Country, to the extent subject to a sanctions program administered by OFAC.

" SEC " means the Securities and Exchange Commission.

" SEC Disclosure Documents " means all reports on Forms 10K, 10Q, and 8K filed by the Borrower with the SEC.

" Single Employer Plan " means a Plan maintained by the Borrower or any member of the Controlled Group for employees of the Borrower or any member of the Controlled Group.

" Stated Amount " means, with respect to any Letter of Credit at any time, the aggregate amount available to be drawn thereunder at such time (regardless of whether any conditions for drawing could then be met).

" Subsidiary " of a Person means (i) any corporation more than 50% of the outstanding securities having the ordinary voting power of which shall at the time be owned or controlled, directly or indirectly, by such Person or by one or more of its Subsidiaries or by such Person and one or more of its Subsidiaries, or (ii) any partnership, limited liability company, association, joint venture or similar business organization more than 50% of the ownership interests having the ordinary voting power of which shall at the time be so owned or controlled. Unless otherwise expressly provided, all references herein to a " Subsidiary " shall mean a Subsidiary of the Borrower.

" Swingline Commitment " means $35,000,000 or, if less, the Aggregate Commitments at the time of determination, as such amount may be reduced at or prior to such time pursuant to the terms hereof.

" Swingline Exposure " means, with respect to any Lender at any time, its maximum aggregate liability to make Refunded Swingline Loans pursuant to Section 2.2.4 or to purchase participations pursuant to Section 2.2.5 in Swingline Loans that are outstanding at such time.

" Swingline Lender " means Wells Fargo in its capacity as maker of Swingline Loans, and its successors in such capacity.

" Swingline Termination Date " means the date that is five Business Days prior to the Repayment Date.

" Swingline Note " means a promissory note issued at the request of a Lender pursuant to Section 2.11.4 , substantially in the form of Exhibit 2.11.4-B .

" Syndication Agent " means BTMU, in its capacity as syndication agent hereunder.

" Taxes " means all present or future taxes, levies, imposts, duties, deductions, withholdings (including backup withholding), assessments, fees or other charges imposed by any Governmental Authority, including any interest, additions to tax or penalties applicable thereto.

" TD " means The TD Bank, N.A., and its successors.

" Transferee " is defined in Section 12.4 .

" Type " means, with respect to any Revolving Loan, its nature as a Base Rate Loan or a LIBOR Rate Loan.

" Unmatured Default " means an event that, but for the lapse of time or the giving of notice, or both, would constitute an Event of Default.

" Unutilized Swingline Commitment " means, with respect to the Swingline Lender at any time, the Swingline Commitment at such time less the aggregate principal amount of all Swingline Loans that are outstanding at such time.

" U.S. Borrower " means any Borrower that is a U.S. Person.

" U.S. Federal Income Taxes " means any U.S. federal Taxes described in Section 871(a) or 881(a) of the Code, or any successor provision (or any withholding with respect to such Taxes).

" U.S. Person " means any Person that is a "United States Person" as defined in section 7701(a)(30) of the Code.

" U.S. Tax Compliance Certificate " has the meaning assigned to such term in Section 2.19.7(ii)(b)(3) .

“ Welfare Plan ” means a “welfare plan”, as such term is defined in section 3(1) of ERISA.

“ Wells Fargo ” means Wells Fargo Bank, National Association, and its successors.

“ Wells Fargo Securities ” means Wells Fargo Securities, LLC, and its successors.

“ Withholding Agent ” means the Borrower and the Administrative Agent.

1.2 Accounting Terms . Unless otherwise specified herein, all accounting terms used herein shall be interpreted, all accounting determinations hereunder shall be made, and all financial statements required to be delivered hereunder shall be prepared in accordance with, GAAP applied on a basis consistent with the most recent audited consolidated financial statements of the Borrower delivered to the Lenders prior to the closing of this Agreement; provided that if the Borrower notifies the Administrative Agent that it wishes to amend any financial covenant in Section 6.6 to eliminate the effect of any change in GAAP on the operation of such covenant (or if the Administrative Agent notifies the Borrower that the Required Lenders wish to amend Section 6.6 for such purpose), then the Borrower’s compliance with such covenant shall be determined on the basis of GAAP as in effect immediately before the relevant change in GAAP became effective, until either such notice is withdrawn or such covenant is amended in a manner satisfactory to the Borrower and the Required Lenders. Notwithstanding the foregoing, for purposes of determining compliance with any covenant (including the computation of any financial covenant) contained herein, Indebtedness of the Borrower and its Subsidiaries shall be deemed to be carried at 100% of the outstanding principal amount thereof, and the effects of FASB ASC 825 on financial liabilities shall be disregarded.

1.3 Other Interpretive Provisions .

(i) Except as otherwise specified herein, all references herein (A) to any Person shall be deemed to include such Person’s successors and assigns and (B) to any Applicable Law defined or referred to herein shall be deemed references to such Applicable Law or any successor Applicable Law as the same may have been or may be amended or supplemented from time to time.

(ii) When used in this Agreement, the words “herein”, “hereof” and “hereunder” and words of similar import shall refer to this Agreement as a whole and not to any provision of this Agreement, and the words “Article”, “Section”, “Schedule” and “Exhibit” shall refer to Articles and Sections of, and Schedules and Exhibits to, this Agreement unless otherwise specified.

(iii) Whenever the context so requires, the neuter gender includes the masculine or feminine, the masculine gender includes the feminine, and the singular number includes the plural, and vice versa.

(iv) Any item or list of items set forth following the word “including”, “include” or “includes” is set forth only for the purpose of indicating that, regardless of whatever other items are in the category in which such item or items are “included”, such item or items are in such category, and shall not be construed as indicating that the items in the category in which such item or items are “included” are limited to such items or to items similar to such items. The word “will” shall be construed to have the same meaning and effect as the word “shall.” Unless the context requires otherwise (a) any definition of or reference to any agreement, instrument or other document herein shall be construed as referring to such agreement, instrument or other document as from time to time amended, supplemented or otherwise modified (subject to any restrictions on such amendments, supplements or modifications set forth herein), (b) the words “asset” and “property” shall be construed to have the same meaning and effect and to refer to any and all tangible and intangible assets and properties, including cash, securities, accounts and contract rights.

(v) Each authorization in favor of the Administrative Agent, the Lenders or any other Person granted by or pursuant to this Agreement shall be deemed to be irrevocable and coupled with an interest.

(vi) All references herein to the Lenders or any of them shall be deemed to include the Issuing Bank and the Swingline Lender unless specifically provided otherwise or unless the context otherwise requires.

(vii) Except as otherwise specified herein, all references to the time of day shall be deemed to be to New York City time as then in effect.

ARTICLE II
CREDIT FACILITY

2.1 The Facility .

2.1.1 Availability of Facility . Subject to the terms of this Agreement, the facility is available from the date hereof to the Facility Termination Date, and the Borrower may borrow, repay and reborrow at any time prior to the Facility Termination Date. Unless sooner terminated pursuant to the terms hereof, the Commitments to lend hereunder shall expire on the Facility Termination Date.

2.1.2 Repayment of Facility . Subject to the terms of this Agreement, any outstanding Loans and all other unpaid Obligations shall be paid in full by the Borrower on the Facility Termination Date; provided that if any authorization of any state official or state regulatory authority required under any Applicable Law, for any borrowing of Loans by the Borrower, expires without being extended at any time prior to the Facility Termination Date (and such authorization is required to be in effect at such time in order for the Borrower to continue to have such Loans and other unpaid Obligations outstanding under Applicable Law), then upon the expiration of such authorization, all outstanding Loans and all other unpaid Obligations shall be immediately paid in full by the Borrower.

2.1.3 Revolving Facility . Each Lender severally agrees, subject to and on the terms and conditions of this Agreement, to make loans (each, a “ Revolving Loan ,” and collectively, the “ Revolving Loans ”) to the Borrower, from time to time on any Business Day during the period from and including the Agreement Date to but not including the Facility Termination Date, in an aggregate principal amount at any time outstanding not exceeding its Commitment; provided that no borrowing of Revolving Loans shall be made if, immediately after giving effect thereto (and to any concurrent repayment of Swingline Loans with proceeds of

Revolving Loans made pursuant to such borrowing), (i) the amount of all outstanding Credit Exposure of any Lender exceed such Lender's Commitment or (ii) the aggregate principal amount of all outstanding Credit Exposure exceed the Aggregate Commitments. Subject to and on the terms and conditions of this Agreement, the Borrower may borrow, repay and reborrow Revolving Loans.

2.1.4 Swingline Facility . The Swingline Lender agrees, subject to and on the terms and conditions of this Agreement, to make loans (each, a " Swingline Loan ," and collectively, the " Swingline Loans ") to the Borrower, from time to time on any Business Day during the period from the Agreement Date to but not including the Swingline Termination Date (or, if earlier, the Facility Termination Date), in an aggregate principal amount at any time outstanding not exceeding the Swingline Commitment. Swingline Loans may be made even if the aggregate principal amount of Swingline Loans outstanding at any time, when added to the aggregate Credit Exposure of the Swingline Lender in its capacity as a Lender outstanding at such time, would exceed the Swingline Lender's own Commitment at such time, but provided that no borrowing of Swingline Loans shall be made if, immediately after giving effect thereto (i) the amount of all outstanding Credit Exposure of any Lender exceed such Lender's Commitment or (ii) the aggregate principal amount of all outstanding Credit Exposure exceeds the Aggregate Commitments, and provided further that the Swingline Lender shall not make any Swingline Loan if any Lender is at that time a Defaulting Lender, unless the Swingline Lender has entered into arrangements satisfactory to the Swingline Lender (in its sole discretion) with the Borrower or such Lender to eliminate the Swingline Lender's actual or potential Fronting Exposure (after giving effect to Section 2.22.1(iv)) with respect to the Defaulting Lender arising from either the Swingline Loan then proposed to be made or that the Swingline Loan and all other Swingline Loans as to which the Swingline Lender has actual or potential Fronting Exposure, as it may elect in its sole discretion. Subject to and on the terms and conditions of this Agreement, the Borrower may borrow, repay (including by means of a borrowing of Revolving Loans pursuant to Section 2.2.3) and reborrow Swingline Loans. All Swingline Loans shall bear interest at the LIBOR Market Index Rate plus the Applicable Margin.

2.2 Loans .

2.2.1 Types of Loans . The Revolving Loans may be made as, and from time to time continued as or converted to, Base Rate Loans or LIBOR Rate Loans (each a " Type " of Loan), or a combination thereof, selected by the Borrower in accordance with Section 2.2.2 . The Swingline Loans shall be made and maintained as LIBOR Market Index Rate Loans at all times and may not be converted into or continued as LIBOR Rate Loans or Base Rate Loans under Section 2.2.7 .

2.2.2 Borrowing of Revolving Loans . In order to request Revolving Loans (other than (i) borrowings of Swingline Loans, which shall be made pursuant to Section 2.2.3 , (ii) borrowings for the purpose of repaying Refunded Swingline Loans, which shall be made pursuant to Section 2.2.4 , (iii) borrowings for the purpose of paying unpaid Reimbursement Obligations, which shall be made pursuant to Section 3.4 , and (iv) borrowings involving continuations or conversions of outstanding Loans, which shall be made pursuant to Section 2.2.7), the Borrower shall give the Administrative Agent irrevocable written notice (a " Borrowing Notice "), not later than 11:00 a.m. on the requested Borrowing Date of each Base

Rate Loan and at least three Business Days before the requested Borrowing Date for each LIBOR Rate Loan. A Borrowing Notice shall be in the form of Exhibit 2.2.2 hereto and shall specify:

(i) the requested Borrowing Date, which shall be a Business Day, of such Loan,

(ii) the aggregate amount of such Loan,

(iii) the Type of Loan selected, and

(iv) in the case of each LIBOR Rate Loan, the Interest Period applicable thereto (which may not end after the Facility Termination Date).

Each LIBOR Rate Loan shall be in the minimum amount of $5,000,000 (and any whole multiple of $1,000,000 in excess thereof), and each Base Rate Loan shall be in the minimum amount of $1,000,000 (and any whole multiple of $1,000,000 in excess thereof); provided , however , any Base Rate Loan may be in the amount of the unused Aggregate Commitments. If the Borrower shall have failed to designate the Type of Loans selected, the Borrower shall be deemed to have requested Base Rate Loans. If the Borrower shall have failed to select the duration of the Interest Period to be applicable to any LIBOR Rate Loans requested, then the Borrower shall be deemed to have selected an Interest Period with a duration of one month.

Upon receipt of any such notice, the Administrative Agent shall promptly notify each Lender of the contents thereof and of the amount and Type of each Loan to be made by such Lender on the requested date specified therein. To the extent such Lenders have made such amounts available to the Administrative Agent as provided in Section 2.3 , the Administrative Agent will make the aggregate of such amounts available to the Borrower in like funds as received by the Administrative Agent.

2.2.3 Borrowing of Swingline Loans . In order to request Swingline Loans, the Borrower shall give the Administrative Agent (and the Swingline Lender, if the Swingline Lender is not also the Administrative Agent) irrevocable written notice (a " Swingline Borrowing Notice ") not later than 11:00 a.m., on the date of requested Borrowing Date. A Borrowing Notice shall be in the form of Exhibit 2.2.3 hereto and shall specify:

(i) the requested Borrowing Date, which shall be a Business Day, of such Loan, and

(ii) the aggregate amount of such Loan.

Each Swingline Loan (x) shall be in the minimum amount of $100,000 (and a whole multiple of $100,000 if in excess thereof (or if less, in the amount of the Unutilized Swingline Commitment)) and (y) shall be due and payable on the earlier of (A) the Swingline Termination Date and (B) within ten Business Days of such Loan being made. To the extent the Swingline Lender has made such amount available to the Administrative Agent as provided in Section 2.3 , the Administrative Agent will make such amount available to the Borrower. Immediately upon the making of a Swingline Loan, each Lender shall be deemed to, and hereby irrevocably and unconditionally agrees to, purchase from the Swingline Lender a risk participation in such Swingline Loan in an amount equal to the product of such Lender's Applicable Percentage times the amount of such Swingline Loan.

2.2.4 Refunded Swingline Loans . With respect to any outstanding Swingline Loans, the Swingline Lender may at any time (whether or not an Event of Default has occurred and is continuing) in its sole and absolute discretion, and is hereby authorized and empowered by the Borrower to, cause a Borrowing of Revolving Loans to be made for the purpose of repaying such Swingline Loans by delivering to the Administrative Agent (if the Administrative Agent is not also the Swingline Lender) and each other Lender (on behalf of, and with a copy to, the Borrower), not later than 11:00 a.m. on the proposed Borrowing Date therefor, a notice (which shall be deemed to be a Borrowing Notice given by the Borrower) requesting the Lenders to make Revolving Loans (which shall be made initially as Base Rate Loans) on such Borrowing Date in an aggregate amount equal to the amount of such Swingline Loans (the " Refunded Swingline Loans ") outstanding on the date such notice is given that the Swingline Lender requests to be repaid. To the extent the Lenders have made such amounts available to the Administrative Agent as provided in Section 2.3 , the Administrative Agent will make the aggregate of such amounts available to the Swingline Lender in like funds as received by the Administrative Agent, which shall apply such amounts in repayment of the Refunded Swingline Loans. Notwithstanding any provision of this Agreement to the contrary, on the relevant Borrowing Date, the Refunded Swingline Loans (including the Swingline Lender's ratable share thereof, in its capacity as a Lender) shall be deemed to be repaid with the proceeds of the Revolving Loans made as provided above (including a Revolving Loan deemed to have been made by the Swingline Lender), and such Refunded Swingline Loans deemed to be so repaid shall no longer be outstanding as Swingline Loans but shall be outstanding as Revolving Loans. If any portion of any such amount repaid (or deemed to be repaid) to the Swingline Lender shall be recovered by or on behalf of the Borrower from the Swingline Lender in any bankruptcy, insolvency or similar proceeding or otherwise, the loss of the amount so recovered shall be shared ratably among all the Lenders in the manner contemplated by Section 2.3 .

2.2.5 Lender Participation in Swingline Loans . If, as a result of any bankruptcy, insolvency or similar proceeding with respect to the Borrower, Revolving Loans are not made pursuant to Section 2.2.4 in an amount sufficient to repay any amounts owed to the Swingline Lender in respect of any outstanding Swingline Loans, or if the Swingline Lender is otherwise precluded for any reason from giving a notice on behalf of the Borrower as provided for hereinabove, each Lender, upon one Business Day's prior notice from the Swingline Lender, shall fund its risk participation in such outstanding Swingline Loans by making available to the Administrative Agent an amount equal to its Applicable Percentage of the unpaid amount thereof together with accrued interest thereon. To the extent the Lenders have made such amounts available to the Administrative Agent as provided Section 2.3 , the Administrative Agent will make the aggregate of such amounts available to the Swingline Lender in like funds as received by the Administrative Agent. In the event any such Lender fails to make available to the Administrative Agent the amount of such Lender's participation as provided in this Section 2.2.5 , the Swingline Lender shall be entitled to recover such amount on demand from such Lender, together with interest thereon for each day from the date such amount is required to be made available for the account of the Swingline Lender until the date such amount is made available to the Swingline Lender at the Federal Funds Effective Rate for the first three Business Days and thereafter at the Alternative Base Rate. Promptly following its receipt of any payment by or on behalf of the Borrower in respect of a Swingline Loan, the Swingline Lender will pay to each Lender that has acquired a participation therein such Lender's Applicable Percentage of such payment.

2.2.6 Notwithstanding any provision of this Agreement to the contrary, the obligation of each Lender (other than the Swingline Lender) to make Revolving Loans for the purpose of repaying any Refunded Swingline Loans pursuant to Section 2.2.4 and each such Lender's obligation to purchase a participation in any unpaid Swingline Loans pursuant to Section 2.2.5 shall be absolute and unconditional and shall not be affected by any circumstance or event whatsoever, including, without limitation, (i) any set-off, counterclaim, recoupment, defense or other right that such Lender may have against the Swingline Lender, the Administrative Agent, the Borrower or any other Person for any reason whatsoever, (ii) the occurrence or continuance of any Unmatured Default or Event of Default, (iii) the failure of the amount of such borrowing of Revolving Loans to meet the minimum borrowing amount specified in Section 2.2.2 , or (iv) the failure of any conditions set forth in Section 4.2 or elsewhere herein to be satisfied.

2.2.7 Conversion and Continuation of Outstanding Loans .

(i) Each Base Rate Loan shall continue as a Base Rate Loan unless and until such Base Rate Loan is either converted into a LIBOR Rate Loan in accordance with this Section 2.2.7 or repaid in accordance with Section 2.5 . Each LIBOR Rate Loan shall continue as a LIBOR Rate Loan until the end of the then applicable Interest Period therefor, at which time such LIBOR Rate Loan shall be automatically converted into a Base Rate Loan unless the Borrower shall have given the Administrative Agent a Conversion/Continuation Notice in the manner set forth below requesting that, at the end of such Interest Period, such LIBOR Rate Loan continue as a LIBOR Rate Loan for the same or another Interest Period. The Borrower may elect from time to time to convert all or any part of a Base Rate Loan into a LIBOR Rate Loan. The Borrower shall give the Administrative Agent irrevocable notice in the form of Exhibit 2.2.7 (a " Conversion/Continuation Notice ") of each conversion of a Base Rate Loan into a LIBOR Rate Loan, or continuation of a LIBOR Rate Loan, not later than 11:00 a.m. at least three Business Days prior to the date of the requested conversion or continuation, specifying:

(a) the requested date, which shall be a Business Day, of such conversion or continuation,

(b) the aggregate amount and Type of the Loan which is to be converted or continued, and

(c) the amount of such Loan(s) which is to be converted or continued as a LIBOR Rate Loan and the duration of the Interest Period applicable thereto.

Each conversion of a LIBOR Rate Loan into a Base Rate Loan shall involve a minimum amount of $3,000,000 (and a whole multiple of $1,000,000, if in excess thereof). Each conversion of a Base Rate Loan into a LIBOR Rate Loan shall involve a minimum amount of $5,000,000 (and a whole multiple of $1,000,000 if in excess thereof). No partial conversion of LIBOR Rate Loans made pursuant to a single Borrowing Notice shall reduce the outstanding principal amount of such LIBOR Rate Loans to less than $5,000,000 (or to any greater amount not a whole multiple of $1,000,000 in excess thereof). Except as otherwise provided in Section 2.18.6 , LIBOR Rate Loans may be converted into Base Rate Loans only on the last day of the Interest Period Applicable thereto (and in any event, if a LIBOR Rate Loan is converted into a Base Rate Loan on any day other than the last day of the Interest Period applicable thereto, the Borrower will pay, upon such conversion, all amounts required under Section 2.18.1 to be paid as a consequence thereof).

Upon receipt of any such notice, the Administrative Agent shall promptly notify each Lender of (x) the contents thereof, (y) the amount and Type and, in the case of LIBOR Rate Loans, the last day of the applicable Interest Period of each Loan to be converted or continued by such Lender and (z) the amount and Type or Types of Loans into which such Loans are to be converted or as which such Loan are to be continued.

(ii) Notwithstanding anything to the contrary contained in this Section 2.2.7 , during an Event of Default, the Administrative Agent may notify the Borrower that Loans may only be converted into or continued as Loans of certain specified Types.

2.3 Funding by Lenders; Disbursement to the Borrower.

2.3.1 Funding by Lenders . Not later than 1:00 p.m. on each requested Borrowing Date, each Lender shall, if it has received the notice contemplated by Sections 2.2.2 , 2.2.3 , 2.2.4 or 2.2.5 on or prior to 12:00 noon on such date, in the case of Base Rate Loans, or on or prior to its close of business on the third Business Day before such date, in the case of LIBOR Rate Loans, make available to the Administrative Agent, in Dollars in funds immediately available to the Administrative Agent at its address specified pursuant to Article XIII , the amount of Loans to be made by such Lender on such date.

2.3.2 Disbursement to the Borrower . Upon satisfaction of the applicable conditions set forth in Section 4.2 (and, if such Borrowing is on the Agreement Date, Section 4.1), Loans shall be disbursed by the Administrative Agent not later than 3:30 p.m. on the date specified therefor by credit to an account of the Borrower at the Administrative Agent at its address specified pursuant to Article XIII or in such other manner as may have been specified to and as shall be reasonably acceptable to the Administrative Agent, in each case in Dollars in funds immediately available to the Borrower, as the case may be.

2.4 Fees . The Borrower agrees to pay:

2.4.1 Arranger Fees . (i) To Wells Fargo Securities and BTMU, for their own respective accounts, on the Agreement Date, the fees required under the Active Arrangers Fee Letter and (ii) BCM and TD, for their respective accounts, on the Agreement Date, the fees required under the Passive Arrangers Fee Letter;

2.4.2 Facility Fee . To the Administrative Agent for the account of each Lender a facility fee at a per annum rate equal to the Facility Fee Rate on the average daily amount of such Lender’s Commitment (whether used or unused) from the date hereof to and including the Repayment Date (the “ Facility Fee ”), payable on the last day of each calendar quarter hereafter and on the Repayment Date.

2.4.3 Letter of Credit Fees . To the Administrative Agent, for the account of each Lender, a letter of credit fee for each calendar quarter (or portion thereof) in respect of all Letters of Credit outstanding during such quarter, at a rate per annum equal to the Applicable Margin then in effect during such quarter for LIBOR Rate Loans on such Lender's pro rata share of the daily average aggregate Stated Amount of such Letters of Credit, payable in arrears on (i) the last Business Day of each calendar quarter, beginning with the first such day to occur after the Agreement Date, and (ii) on the later of the Facility Termination Date and the date of termination of the last outstanding Letter of Credit; provided , however , that any letter of credit fees otherwise payable for the account of a Defaulting Lender with respect to any Letter of Credit as to which such Defaulting Lender has not provided Cash Collateral satisfactory to the Issuing Bank pursuant to Section 3.1.1 shall be payable, to the maximum extent permitted by Applicable Law, to the other Lenders in accordance with the upward adjustments in their respective pro rata shares allocable to such Letter of Credit pursuant to Section 2.22.1(iv) , with the balance of such fee, if any, payable to the Issuing Bank for its own account;

2.4.4 Letter of Credit Facing Fee . To each Issuing Bank, for its own account, a facing fee for each calendar quarter (or portion thereof) on the daily average aggregate Stated Amount of all Letters of Credit issued by such Issuing Bank outstanding during such quarter, at a per annum rate separately agreed to between each Issuing Bank and the Borrower (each an " LC Fee "), payable in arrears (i) on the last Business Day of each calendar quarter, beginning with the first such day to occur after the Agreement Date, and (ii) on the later of the Facility Termination Date and the date of termination of the last outstanding Letter of Credit;

2.4.5 Letter of Credit Customary Fees . To each Issuing Bank, for its own account, such commissions, transfer fees and other fees and charges incurred in connection with the issuance and administration of each Letter of Credit issued by it as are customarily charged from time to time by such Issuing Bank for the performance of such services in connection with similar letters of credit, or as may be otherwise agreed to by such Issuing Bank, but without duplication of amounts payable under Section 2.4.2 ; and

2.4.6 Administrative Fee . To the Administrative Agent, for its own account, the annual administrative fee described in the Administrative Fee Letter, on the terms, in the amount and at the times set forth therein.

None of the fees payable under this Section 2.4 shall be refundable in whole or in part.

2.5 Reductions in Aggregate Commitments; Increases in Aggregate Commitments.

2.5.1 Reductions . The Borrower may permanently reduce the Aggregate Commitments, in whole or in part, ratably among the Lenders in an amount equal to $5,000,000 ($500,000 in the case of the Unutilized Swingline Commitment) or a whole multiple of $1,000,000 in excess thereof (or $100,000 in the case of the Unutilized Swingline Commitment) upon at least three Business Days' written notice to the Administrative Agent (and in the case of a termination or reduction of the Unutilized Swingline Commitment, the Swingline Lender), which notice shall specify the amount of any such reduction; provided , however , that the amount of the Aggregate Commitments may not be reduced below the aggregate outstanding Credit Exposure. Upon receipt of any such notice, the Administrative Agent (or Swingline Lender) shall promptly notify each Lender of the contents thereof and the amount to which such Lender's Commitment is to be reduced. All accrued Facility Fees shall be payable on the effective date of any termination of the obligations of the Lenders to make Loans hereunder. The amount of any termination or reduction made under this Section 2.5.1 may not thereafter be reinstated.

2.5.2 Increases . At any time following the Agreement Date and prior to the Facility Termination Date, the Aggregate Commitments may, at the option of the Borrower, be increased by a total amount not in excess of $100,000,000, either by one or more then-existing Lenders increasing their Commitments or by new Lenders establishing such additional Commitments (each such increase by either means, a " Commitment Increase ", and each such Lender increasing its Commitment or new Lender, an " Additional Commitment Lender "); provided that (i) each new Lender shall be reasonably acceptable to the Administrative Agent, (ii) no Unmatured Default or Event of Default shall exist immediately prior to or after the effective date of such Commitment Increase, (iii) all representations and warranties made by the Borrower in this Agreement as of the date of such Commitment Increase are true and correct in all material respects, (iv) each such Commitment Increase shall be in an aggregate amount not less than $10,000,000 or a whole multiple of $5,000,000 in excess thereof, or, if less, the maximum remaining amount that the Aggregate Commitments may be increased pursuant to this Section 2.5.2 , (v) no such Commitment Increase shall be permitted without all required Governmental Approvals and (vi) no such Commitment Increase shall become effective unless and until the Borrower, the Administrative Agent and the Additional Commitment Lenders shall have executed and delivered an agreement substantially in the form of Exhibit 2.5.2 (a " Commitment Increase Supplement "). On the effective date of such Commitment Increase, each Additional Commitment Lender shall purchase, by assignment, from each other existing Lender the portion of such other Lender's Credit Exposure outstanding at such time such that, after giving effect to such assignments, the respective aggregate amount of Credit Exposure of each Lender shall be equal to such Lender's Applicable Percentage (as adjusted pursuant hereto) of the aggregate Credit Exposure outstanding. The purchase price for the Loans so assigned shall be the principal amount of the Loans so assigned plus the amount of accrued and unpaid interest thereon on the date of assignment. Upon payment of such purchase price, each Lender shall be automatically deemed to have sold and made such an assignment to such Additional Commitment Lender and shall, to the extent of the interest assigned, be released from its obligations under this Agreement, and such Additional Commitment Lender shall be automatically deemed to have purchased and assumed such an assignment from each other Lender and, if not already a Lender hereunder, shall be a party hereto and, to the extent of the interest assigned, have the rights and obligations of a Lender under this Agreement.

2.6 Extension Option . After the first anniversary of the Agreement, and then no earlier than 60 days and no later than 30 days prior to each anniversary of the Agreement Date, but on no more than two occasions, the Borrower may, by written notice to the Administrative Agent, request that the Lenders extend the Facility Termination Date for an additional year. Any election by a Lender to extend the term of its Commitment pursuant to such a request shall be at such Lender's sole discretion and subject to such credit evaluation as such Lender may determine.

2.6.1 No extension pursuant to this Section 2.6 shall become effective unless agreed to in writing not later than 15 days prior to the relevant anniversary of the Agreement Date by Lenders then holding more than 50% of the Commitments.

2.6.2 In the event that Lenders then holding more than 50% of the Commitments but less than 100% of the Commitments shall agree to an extension requested pursuant to this Section 2.6 , the Borrower shall be entitled to propose a new Lender or Lenders (which shall be reasonably acceptable to the Administrative Agent, the Swingline Lender and the Issuing Banks), or an increase in the Commitment or Commitments of a then existing Lender or Lenders, whose new or increased Commitments (in an aggregate amount not in excess of the Commitments of the Lenders who did not agree to extend) shall be in effect during the extension period so agreed.

2.6.3 Unless a Lender which does not agree to extend its Commitment shall be replaced pursuant to Section 2.6.4 , the Commitment of such Lender shall continue in full force and effect until the Facility Termination Date to which it has agreed (each a " Prior Termination Date ").

2.6.4 In the event that an existing Lender shall not agree to extend its Commitment pursuant to a request by the Borrower, the Borrower shall be entitled to replace such Lender with another Lender or and/or an Eligible Assignee that shall assume the then Commitment of such existing Lender and shall agree to the extension requested. Any Eligible Assignee (if not already a Lender hereunder) shall become a party to this agreement as a Lender pursuant to a joinder agreement in form and substance reasonably satisfactory to the Administrative Agent and the Borrower. In the event of such a replacement, such existing Lender shall assign to such replacement Lender the outstanding Loans of such existing Lender for a purchase price equal to the principal amount of the Loans so assigned, plus the amount of accrued and unpaid interest thereon to the date of such assignment, and such replacement Lender shall acquire (and fund as appropriate) its full pro rata share of all Loans and participations in Letters of Credit and Swingline Loans in accordance with its Applicable Percentage.

2.6.5 An extension of the Facility Termination Date pursuant to this Section 2.6 shall only become effective upon the receipt by the Administrative Agent of a certificate (the statements contained in which shall be true) of a duly authorized officer of the Borrower stating that both before and after giving effect to such extension of the Facility Termination Date (i) no Unmatured Default or Event of Default has occurred and is continuing and (ii) all representations and warranties made by the Borrower under this Agreement are true and correct in all material respects on and as of the date such extension is made.

2.6.6 Effective on and after the Prior Termination Date, (i) each of the Lenders who does not agree to extend its Commitment shall be automatically released from their respective participations and Reimbursement Obligations under Section 3.4 with respect to any outstanding Letters of Credit and (ii) the participations and Reimbursement Obligations of each Lender (other than the Lenders who do not agree to extend their Commitments) shall be automatically adjusted to equal such Lender's revised Applicable Percentage of such outstanding Letters of Credit.

2.7 Repayments; Optional Principal Prepayments.

(a) Each Loan shall mature and become due and payable, and shall be repaid by the Borrower, in full on the day one year after the date such Loan was made, unless the Borrower's Board of Directors, by a written resolution, has authorized such Loan to be outstanding for a term in excess of one year, in which case such Loan shall mature and become due and payable, and shall be repaid by the Borrower, in full on the date fixed by such written resolution, but in no event later than on the Facility Termination Date.

(b) The Borrower may from time to time pay, without penalty or premium, all outstanding Loans, or any portion of the outstanding Loans, on any Business Day upon notice to the Administrative Agent one Business Day prior to each intended prepayment of Alternative Base Rate Loans and three Business Days prior to each intended prepayment of LIBOR Rate Loans; provided that (i) each partial payment of LIBOR Rate Loans shall be in the minimum amount of $5,000,000 (and a whole multiple of $1,000,000 if in excess thereof), and each partial payment of Base Rate Loans shall be in the minimum amount of $3,000,000 (and a whole multiple of $1,000,000 if in excess thereof) ($100,000 and $100,000, respectively, in the case of Swingline Loans), (ii) no partial payment of LIBOR Rate Loans made pursuant to a single borrowing shall reduce the aggregate outstanding principal amount of the remaining LIBOR Rate Loans under such borrowing to less than $5,000,000 (and a whole multiple of $1,000,000 if in excess thereof), and (iii) unless made together with all amounts required under Section 2.18.1 to be paid as a consequence of such prepayment, a prepayment of a LIBOR Rate Loan may be made only on the last day of the Interest Period applicable thereto. Each such notice of prepayment shall be in the form of Exhibit 2.7 and shall specify (i) the date such prepayment is to be made and (ii) the amount and Type of the Loans to be prepaid and, in the case of LIBOR Rate Loans, the last day of the applicable Interest Period of the LIBOR Rate Loans to be prepaid. Upon receipt of any such notice, the Administrative Agent shall promptly notify each Lender of the contents thereof and the amount and Type of the Loans to be prepaid and, in the case of LIBOR Rate Loans, the last day of the applicable Interest Period of each LIBOR Rate Loan of such Lender to be prepaid. Amounts to be prepaid shall irrevocably be due and payable on the date specified in the applicable notice of prepayment, together with interest thereon as provided in Section 2.13.

2.8 Changes in Interest Rate, etc . Each Base Rate Loan shall bear interest on the outstanding principal amount thereof, for each day from and including the date such Loan is made or is converted from a LIBOR Rate Loan into a Base Rate Loan pursuant to Section 2.2.7 to but excluding the date it becomes due or is converted into a LIBOR Rate Loan pursuant to Section 2.2.7 hereof, at a rate per annum equal to the Base Rate plus the Applicable Margin for such day. Each LIBOR Rate Loan shall bear interest on the outstanding principal amount thereof from and including the first day of the Interest Period applicable thereto to (but not including) the last day of such Interest Period at the applicable LIBOR Rate plus the Applicable Margin. No Interest Period may end after the Facility Termination Date.

2.9 Rates Applicable After Default . During the continuance of an Unmatured Default the Required Lenders may, at their option, by notice to the Borrower (which notice may be revoked at the option of the Required Lenders notwithstanding any provision of Section 8.2 requiring unanimous consent of the Lenders to changes in interest rates), declare that no Loan may be made as, converted into, or continued as a LIBOR Rate Loan. During the continuance of an Event of Default the Required Lenders may, at their option, by notice to the Borrower (which notice may be revoked at the option of the Required Lenders notwithstanding any provision of Section 8.2 requiring unanimous consent of the Lenders to changes in interest rates), declare that each Loan and all other amounts payable under the Loan Documents shall bear interest at the Overdue Rate; provided that, during the continuance of an Event of Default under Sections 7.1 , 7.7 or 7.8 , any amount payable under the Loan Documents not paid when due (whether at maturity, by reason of notice of prepayment or otherwise) shall bear interest at a rate per annum equal to the Overdue Rate without any election or action on the part of the Administrative Agent or any Lender.

2.10 Method of Payment.

2.10.1 Payments by Borrower . All payments of the Obligations hereunder and under the other Loan Documents shall be made, observed or performed, without setoff, deduction, or counterclaim (whether sounding in tort, contract or otherwise) or Tax. All amounts payable for the account of the Administrative Agent shall be paid in immediately available funds to the Administrative Agent at the Administrative Agent's address specified pursuant to Article XIII , or at any other Lending Installation of the Administrative Agent specified in writing by the Administrative Agent to the Borrower, by noon on the date when due and shall be applied ratably by the Administrative Agent among the Lenders. All amounts payable for the account of any Lender under the Loan Documents shall, in the case of payments on account of principal of or interest on the Loans or fees, be made to the Administrative Agent at the Administrative Agent's address specified pursuant to Article XIII and, in the case of all other payments, be made directly to such Lender at its address specified pursuant to Article XIII or at such other address as such Lender may designate by notice to the Borrower.

2.10.2 Payments to Lenders . Each payment delivered to the Administrative Agent for the account of any Lender shall be delivered promptly by the Administrative Agent to such Lender in the same type of funds that the Administrative Agent received at its address specified pursuant to Article XIII or at any Lending Installation specified in a notice received by the Administrative Agent from such Lender. Notwithstanding the foregoing or any contrary provision hereof, if any Lender shall fail to make any payment required to be made by it hereunder to the Administrative Agent, any Issuing Bank or the Swingline Lender, then the Administrative Agent may, in its discretion, apply any amounts thereafter received by the Administrative Agent for the account of such Lender to satisfy such Lender's obligations to the Administrative Agent, such Issuing Bank or the Swingline Lender, as the case may be, until all such unsatisfied obligations are fully paid. If the Administrative Agent shall not have made a required distribution to the appropriate Lenders as required hereinabove after receiving a payment for the account of such Lenders, the Administrative Agent will pay to each such Lender, on demand, its ratable share of such payment with interest thereon at the Federal Funds Effective Rate for each day from the date such amount was required to be disbursed by the Administrative Agent until the date repaid to such Lender. The Administrative Agent will distribute to each Issuing Bank like amounts relating to payments made to the Administrative Agent for the account of such Issuing Bank in the same manner, and subject to the same terms and conditions, as set forth hereinabove with respect to distributions of amounts to the Lenders.

2.10.3 Authorization to Charge the Borrower’s Accounts . The Borrower hereby authorizes the Administrative Agent and each Lender, if and to the extent any amount payable by the Borrower under the Loan Documents (whether payable to such Person or to any other Person that is the Administrative Agent or a Lender) is not otherwise paid when due, to charge such amount against any or all of the accounts of the Borrower with such Person or any of its Affiliates (whether maintained at a branch or office located within or without the United States), with the Borrower remaining liable for any deficiency. Any Lender charging an amount against an account of the Borrower shall comply with Section 11.2 and provide notice thereof to the Borrower, within a reasonable time thereafter, which notice shall include a description in reasonable detail of such action.

2.11 Evidence of Indebtedness.

2.11.1 Lenders’ Evidence of Indebtedness . Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Loan made by such Lender from time to time, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

2.11.2 Administrative Agent’s Evidence of Indebtedness. The Administrative Agent shall also maintain the Register of accounts pursuant to Section 12.3.4 in which it will record (a) the amount of each Loan made hereunder, the Type thereof and the Interest Period with respect thereto, (b) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (c) the amount of any sum received by the Administrative Agent hereunder from the Borrower and each Lender’s share thereof.

2.11.3 Effect of Entries . The entries maintained in the accounts and records maintained pursuant to Sections 2.11.1 and 2.11.2 above shall be prima facie evidence of the existence and amounts of the Obligations therein recorded; provided , however , that the failure of the Administrative Agent or any Lender to maintain such accounts and records or any error therein shall not in any manner affect the obligation of the Borrower to repay the Obligations in accordance with their terms.

2.11.4 Notes Upon Request . Any Lender may request that its Loans be evidenced by Notes. In such event, the Borrower shall prepare, execute and deliver to such Lender (a) in the case of Revolving Loans, a Revolving Note in the form of Exhibit 2.11.4-A , payable to the order of such Lender and (b) in the case of Swingline Loans, a Swingline Note in the form of Exhibit 2.11.4-B . Thereafter, the Loans represented by such Note and interest thereon shall at all times (including after any assignment pursuant to Section 12.3) be evidenced by a Note payable to the order of the payee named therein or any assignee pursuant to Section 12.3 , except to the extent that any such Lender or assignee subsequently returns any such Note for cancellation and requests that such Loans once again be evidenced as described in paragraphs 2.11.1 and 2.11.1 above.

2.12 Telephonic Notices . The Borrower hereby authorizes the Lenders and the Administrative Agent to extend, convert, or continue Loans; to effect selections of Types of Loans; and to transfer funds based on telephonic notices made by any Person or Persons the Administrative Agent or any Lender in good faith believes to be acting on behalf of the Borrower, it being understood that the foregoing authorization is specifically intended to allow Borrowing Notices, Swingline Borrowing Notices, and Conversion/Continuation Notices to be given telephonically. The Borrower agrees to deliver promptly to the Administrative Agent a written confirmation, if such confirmation is requested by the Administrative Agent or any Lender, of each telephonic notice signed by an Authorized Officer. If the written confirmation differs in any material respect from the action taken by the Administrative Agent and the Lenders, the records of the Administrative Agent and the Lenders shall govern absent manifest error.

2.13 Interest Payment Dates; Interest and Fee Basis . Interest accrued on each Base Rate Loan and each LIBOR Market Index Rate Loan shall be payable on each Payment Date, commencing with the first such date to occur after the Agreement Date, on any date on which the Base Rate Loan or LIBOR Market Index Rate Loan is prepaid, whether due to acceleration or otherwise, and at maturity. Interest accrued on that portion of the outstanding principal amount of any Base Rate Loan converted into a LIBOR Rate Loan on a day other than a Payment Date shall be payable on the date of conversion. Interest accrued on each LIBOR Rate Loan shall be payable on the last day of its applicable Interest Period, on any date on which the Loan is prepaid, whether by acceleration or otherwise, and at maturity. Interest accrued on each LIBOR Rate Loan having an Interest Period longer than three months shall also be payable on the last day of each three month interval during such Interest Period. Interest, Facility Fees and LC Fees shall be calculated for actual days elapsed on the basis of a 360 day year, except that interest calculated based on the Prime Rate shall be calculated for actual days elapsed on the basis of a 365, or when appropriate 366, day year. Interest shall be payable for the day a Loan is made but not for the day of any payment on the amount paid if payment is received prior to noon (local time) at the place of payment. Whenever any payment to the Administrative Agent or any Lender under the Loan Documents would otherwise be due on a day that is not a Business Day, such payment shall instead be due on the next succeeding Business Day; provided , however , that if such next succeeding Business Day falls in a new calendar month, such payment shall instead be due on the immediately preceding Business Day. If the date any payment under the Loan Documents is due is extended (whether by operation of any Loan Document, Applicable Law or otherwise), such payment shall bear interest for such extended time at the rate of interest applicable hereunder. Interest at the Overdue Rate shall be payable on demand.

2.14 Notification of Loans, Interest Rates, Prepayments and Commitment Reductions . Promptly after receipt thereof, the Administrative Agent will notify each Lender of the contents of each Aggregate Commitments reduction notice, Borrowing Notice, Swingline Notice, Conversion/Continuation Notice, Letter of Credit Notice, Commitment Increase Supplement and repayment notice received by it hereunder. The Administrative Agent will notify each Lender of the LIBOR Rate or Alternate Base Rate applicable to each Loan promptly upon determination of such interest rate and will give each Lender prompt notice of each change in the Alternate Base Rate. The Administrative Agent will notify each Lender of any request by the Borrower pursuant to Section 2.6 to extend the Facility Termination Date.

2.15 Lending Installations. Each Lender may book its Loans at any Lending Installation selected by such Lender and may change its Lending Installation from time to time. All terms of this Agreement shall apply to any such Lending Installation and any Notes issued hereunder shall be deemed held by each Lender for the benefit of any such Lending Installation. Each Lender may, by written notice to the Administrative Agent and the Borrower in accordance with Article XIII, designate replacement or additional Lending Installations through which Loans will be made by it and for whose account Loan payments are to be made. A Lender may designate a separate Lending Installation for the purpose of making or maintaining different Types of Loans, and with respect to LIBOR Rate Loans such office may be a domestic or foreign branch or Affiliate of such Lender.

2.16 Non-Receipt of Funds by the Administrative Agent. Unless the Borrower or a Lender, as the case may be, notifies the Administrative Agent prior to the date on which it is scheduled to make payment to the Administrative Agent of (i) in the case of a Lender, the proceeds of a Loan or (ii) in the case of the Borrower, a payment of principal, interest or fees to the Administrative Agent for the account of the Lenders, that it does not intend to make such payment, the Administrative Agent may assume that such payment has been made. The Administrative Agent may, but shall not be obligated to, make the amount of such payment available to the intended Recipient or Recipients in reliance upon such assumption. If such Lender or the Borrower, as the case may be, has not in fact made such payment to the Administrative Agent, the Recipient of such payment shall, on demand by the Administrative Agent, repay to the Administrative Agent the amount so made available together with interest thereon in respect of each day during the period commencing on the date such amount was so made available by the Administrative Agent until the date the Administrative Agent recovers such amount at a rate per annum equal to the Federal Funds Effective Rate for such day for the first three days and, thereafter, at the Alternate Base Rate plus 2%.

2.17 Maximum Interest Rate. Nothing contained in the Loan Documents shall require the Borrower at any time to pay interest at a rate exceeding the Maximum Permissible Rate. If interest payable by the Borrower on any date would exceed the maximum amount permitted by the Maximum Permissible Rate, such interest payment shall automatically be reduced to such maximum permitted amount, and interest for any subsequent period, to the extent less than the maximum amount permitted for such period by the Maximum Permissible Rate, shall be increased by the unpaid amount of such reduction. Any interest actually received for any period in excess of such maximum amount permitted for such period shall be deemed to have been applied as a prepayment of the Loans.

2.18 Increased Costs; Change in Circumstances; Illegality.

2.18.1 Increased Costs Generally. If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit, compulsory loan, insurance charge or similar requirement against assets of, deposits with or for the account of, or credit extended or participated in by, any Lender (except the Reserve Requirement reflected in the LIBOR Rate) or any Issuing Bank;

(ii) subject any Recipient to any Taxes (other than (A) Indemnified Taxes, (B) Taxes described in clauses (ii) through (iv) of the definition of Excluded Taxes and (C) Connection Income Taxes) on its loans, loan principal, letters of credit, commitments, or other obligations, or its deposits, reserves, other liabilities or capital attributable thereto; or

(iii) impose on any Lender or any Issuing Bank or the London interbank market any other condition, cost or expense (other than Taxes) affecting this Agreement or LIBOR Rate Loans or LIBOR Market Index Rate Loans made by such Lender or any Letter of Credit or participation therein;

and the result of any of the foregoing shall be to increase the cost to such Lender, such Issuing Bank or such other Recipient of making, converting to, continuing or maintaining any LIBOR Rate Loan or of maintaining its obligation to make any such Loan, or to increase the cost to such Lender, such Issuing Bank or such other Recipient of participating in, issuing or maintaining any Letter of Credit (or of maintaining its obligation to participate in or to issue any Letter of Credit), or to reduce the amount of any sum received or receivable by such Lender, such Issuing Bank or other Recipient hereunder (whether of principal, interest or any other amount), then, upon request of such Lender, such Issuing Bank or other Recipient, the Borrower will pay to such Lender, such Issuing Bank or other Recipient, as the case may be, such additional amount or amounts as will compensate such Lender, such Issuing Bank or other Recipient, as the case may be, for such additional costs incurred or reduction suffered.

2.18.2 Capital Requirements . If any Lender or any Issuing Bank determines that any Change in Law affecting such Lender or such Issuing Bank or any Lending Installation of such Lender or such Lender's or such Issuing Bank's holding company, if any, regarding capital or liquidity requirements has or would have the effect of reducing the rate of return on such Lender's or such Issuing Bank's capital or on the capital of such Lender's or such Issuing Bank's holding company, if any, as a consequence of this Agreement, the Commitments of such Lender or the Loans made by, or participations in Letters of Credit or Swingline Loans held by, such Lender, or the Letters of Credit issued by such Issuing Bank, to a level below that which such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company could have achieved but for such Change in Law (taking into consideration such Lender's or such Issuing Bank's policies and the policies of such Lender's or such Issuing Bank's holding company with respect to capital adequacy), then from time to time the Borrower will pay to such Lender or such Issuing Bank, as the case may be, such additional amount or amounts as will compensate such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company for any such reduction suffered.

2.18.3 Certificates for Reimbursement . A certificate of a Lender or an Issuing Bank setting forth the amount or amounts necessary to compensate such Lender or such Issuing Bank or its holding company, as the case may be, as specified in Sections 2.18.1 or 2.18.2 and delivered to the Borrower shall be conclusive absent manifest error. The Borrower shall pay such Lender or such Issuing Bank, as the case may be, the amount shown as due on any such certificate within ten days after receipt thereof.

2.18.4 Delay in Requests . Failure or delay on the part of any Lender or any Issuing Bank to demand compensation pursuant to the foregoing provisions of this Section shall not constitute a waiver of such Lender's or such Issuing Bank's right to demand such compensation; provided that the Borrower shall not be required to compensate a Lender or an Issuing Bank pursuant to the foregoing provisions of this Section 2.18 for any increased costs incurred or reductions suffered more than nine months prior to the date that such Lender or such Issuing Bank, as the case may be, notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's or such Issuing Bank's intention to claim compensation therefor (except that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the nine-month period referred to above shall be extended to include the period of retroactive effect thereof).

2.18.5 LIBOR Unavailable . If, (i) on or prior to the first day of any Interest Period, the Administrative Agent shall have determined that adequate and reasonable means do not exist for ascertaining the applicable LIBOR Rate for such Interest Period, (ii) at any time, the Administrative Agent shall have determined that adequate and reasonable means do not exist for ascertaining the applicable LIBOR Market Index Rate, (iii) on or prior to the first day of any Interest Period, the Administrative Agent shall have received written notice from the Required Lenders of their determination that the rate of interest referred to in the definition of "LIBOR Rate" upon the basis of which the LIBOR Rate for LIBOR Rate Loans for such Interest Period is to be determined or will not adequately and fairly reflect the cost to such Lenders of making or maintaining LIBOR Rate Loans during such Interest Period, or (iv) at any time, the Administrative Agent shall have received written notice from the Required Lenders of their determination that the rate of interest referred to in the definition of "LIBOR Market Index Rate" will not adequately and fairly reflect the cost of such Lenders of making LIBOR Market Index Rate Loans, the Administrative Agent will forthwith so notify the Borrower and the Lenders. Upon such notice, (a) all then outstanding LIBOR Rate Loans shall automatically, on the expiration date of the respective Interest Periods applicable thereto (unless then repaid in full), be converted into Base Rate Loans, (b) all then outstanding LIBOR Market Index Rate Loans, shall automatically, on the day of such notice, be converted into Base Rate Loans, (c) the obligation of the Lenders to make, to convert Base Rate Loans into, or to continue, LIBOR Rate Loans shall be suspended (including pursuant to the borrowing to which such Interest Period applies), and (d) any Borrowing Notice, Swingline Borrowing Notice or Conversion/Continuation Notice given at any time thereafter with respect to LIBOR Rate Loans shall be deemed to be a request for Base Rate Loans, in each case until the Administrative Agent or the Required Lenders, as the case may be, shall have determined that the circumstances giving rise to such suspension no longer exist (and the Required Lenders, if making such determination, shall have so notified the Administrative Agent), and the Administrative Agent shall have so notified the Borrower and the Lenders.

2.18.6 Illegality . Notwithstanding any other provision in this Agreement, if, at any time after the date hereof and from time to time, any Lender shall have determined in good faith that the introduction of or any change in any Applicable Law, rule or regulation or in the interpretation or administration thereof by any Governmental Authority charged with the interpretation or administration thereof, or compliance with any guideline or request from any such Governmental Authority (whether or not having the force of law), has or would have the effect of making it unlawful for such Lender to make or to continue to make or maintain LIBOR Rate Loans or LIBOR Market Index Rate Loans, such Lender will forthwith so notify the Administrative Agent and the Borrower. Upon such notice, (i) each of such Lender's then outstanding LIBOR Rate Loans and LIBOR Market Index Rate Loans shall automatically, immediately in the case of LIBOR Market Index Rate Loans and on the expiration date of the applicable Interest Period in the case of any LIBOR Rate Loan (or, to the extent any such LIBOR Rate Loan may not lawfully be maintained as a LIBOR Rate Loan until such expiration date, upon such notice) and to the extent not sooner prepaid, be converted into a Base Rate Loan, (ii) the obligation of such Lender to make, to convert Base Rate Loans into, or to continue, LIBOR Rate Loans shall be suspended (including pursuant to any borrowing for which the Administrative Agent has received a Borrowing Notice but for which the Borrowing Date has not arrived), and (iii) any Borrowing Notice or Conversion/Continuation Notice given at any time thereafter with respect to LIBOR Rate Loans (or Swingline Borrowing Notice given with respect to any Swingline Loans) shall, as to such Lender, be deemed to be a request for a Base Rate Loan, in each case until such Lender shall have determined that the circumstances giving rise to such suspension no longer exist and shall have so notified the Administrative Agent, and the Administrative Agent shall have so notified the Borrower.

2.19 Taxes .

2.19.1 Issuing Bank . For purposes of this Section 2.19 , the term " Lender " includes any Issuing Bank.

2.19.2 Payments Free of Taxes . Any and all payments by or on account of any obligation of the Borrower under any Loan Document shall be made without deduction or withholding for any Taxes, except as required by Applicable Law. If any Applicable Law (as determined in the good faith discretion of an applicable Withholding Agent) requires the deduction or withholding of any Tax from any such payment by a Withholding Agent, then the applicable Withholding Agent shall be entitled to make such deduction or withholding and shall timely pay the full amount deducted or withheld to the relevant Governmental Authority in accordance with Applicable Law and, if such Tax is an Indemnified Tax, then the sum payable by the Borrower shall be increased as necessary so that after such deduction or withholding has been made (including such deductions and withholdings applicable to additional sums payable under this Section) the applicable Recipient receives an amount equal to the sum it would have received had no such deduction or withholding been made.

2.19.3 Payments of Other Taxes by the Borrower . The Borrower shall timely pay to the relevant Governmental Authority in accordance with Applicable Law, or at the option of the Administrative Agent timely reimburse it for the payment of, any Other Taxes.

2.19.4 Indemnification by the Borrower . The Borrower shall indemnify each Recipient, within 10 days after demand therefor, for the full amount of any Indemnified Taxes (including Indemnified Taxes imposed or asserted on or attributable to amounts payable under this Section 2.19) payable or paid by such Recipient or required to be withheld or deducted from a payment to such Recipient and any reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to the Borrower by a Lender (with a copy to the Administrative Agent), or by the Administrative Agent on its own behalf or on behalf of a Lender, shall be conclusive absent manifest error.

2.19.5 Indemnification by the Lenders . Each Lender shall severally indemnify the Administrative Agent, within 10 days after demand therefor, for (i) any Indemnified Taxes attributable to such Lender (but only to the extent that the Borrower has not already indemnified the Administrative Agent for such Indemnified Taxes and without limiting the obligation of the Borrower to do so), (ii) any Taxes attributable to such Lender's failure to comply with the provisions of Section 12.2 relating to the maintenance of a Participant Register and (iii) any Excluded Taxes attributable to such Lender, in each case, that are payable or paid by the Administrative Agent in connection with any Loan Document, and any reasonable expenses arising therefrom or with respect thereto, whether or not such Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to any Lender by the Administrative Agent shall be conclusive absent manifest error. Each Lender hereby authorizes the Administrative Agent to set off and apply any and all amounts at any time owing to such Lender under any Loan Document or otherwise payable by the Administrative Agent to the Lender from any other source against any amount due to the Administrative Agent under this Section 2.19.5.

2.19.6 Evidence of Payments . As soon as practicable after any payment of Taxes by the Borrower to a Governmental Authority pursuant to this Section 2.19 , the Borrower shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

2.19.7 Status of Lenders .

(i) Any Lender that is entitled to an exemption from or reduction of withholding Tax with respect to payments made under any Loan Document shall deliver to the Borrower and the Administrative Agent, at the time or times reasonably requested by the Borrower or the Administrative Agent, such properly completed and executed documentation reasonably requested by the Borrower or the Administrative Agent as will permit such payments to be made without withholding or at a reduced rate of withholding. In addition, any Lender, if reasonably requested by the Borrower or the Administrative Agent, shall deliver such other documentation prescribed by Applicable Law or reasonably requested by the Borrower or the Administrative Agent as will enable the Borrower or the Administrative Agent to determine whether or not such Lender is subject to backup withholding or information reporting requirements. Notwithstanding anything to the contrary in the preceding two sentences, the completion, execution and submission of such documentation (other than such documentation set forth in clauses (ii)(a), (ii)(b) and (ii)(d) below) shall not be required if in the Lender's reasonable judgment such completion, execution or submission would subject such Lender to any material unreimbursed cost or expense or would materially prejudice the legal or commercial position of such Lender.

(ii) Without limiting the generality of the foregoing, in the event that the Borrower is a U.S. Borrower,

(a) any Lender that is a U.S. Person shall deliver to the Borrower and the Administrative Agent on or prior to the date on which such Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed originals of IRS Form W-9 certifying that such Lender is exempt from U.S. federal backup withholding tax;

(b) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), whichever of the following is applicable:

(1) in the case of a Foreign Lender claiming the benefits of an income tax treaty to which the United States is a party (x) with respect to payments of interest under any Loan Document, executed originals of IRS Form W-8BEN establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "interest" article of such tax treaty and (y) with respect to any other applicable payments under any Loan Document, IRS Form W-8BEN establishing an exemption from, or reduction of, U.S. federal withholding Tax pursuant to the "business profits" or "other income" article of such tax treaty;

(2) executed originals of IRS Form W-8ECI;

(3) in the case of a Foreign Lender claiming the benefits of the exemption for portfolio interest under Section 881(c) of the Code, (x) a certificate substantially in the form of Exhibit 2.19-A to the effect that such Foreign Lender is not a "bank" within the meaning of Section 881(c)(3)(A) of the Code, a "10 percent shareholder" of the Borrower within the meaning of Section 881(c)(3)(B) of the Code, or a "controlled foreign corporation" described in Section 881(c)(3)(C) of the Code (a " U.S. Tax Compliance Certificate ") and (y) executed originals of IRS Form W-8BEN; or

(4) to the extent a Foreign Lender is not the beneficial owner, executed originals of IRS Form W-8IMY, accompanied by IRS Form W-8ECI, IRS Form W-8BEN, a U.S. Tax Compliance Certificate substantially in the form of Exhibit 2.19-B or Exhibit 2.19-C , IRS Form W-9, and/or other certification documents from each beneficial owner, as applicable; provided that if the Foreign Lender is a partnership and one or more direct or indirect partners of such Foreign Lender are claiming the portfolio interest exemption, such Foreign Lender may provide a U.S. Tax Compliance Certificate substantially in the form of Exhibit 2.19-D on behalf of each such direct and indirect partner;

(c) any Foreign Lender shall, to the extent it is legally entitled to do so, deliver to the Borrower and the Administrative Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the reasonable request of the Borrower or the Administrative Agent), executed originals of any other form prescribed by Applicable Law as a basis for claiming exemption from or a reduction in U.S. federal withholding Tax, duly completed, together with such supplementary documentation as may be prescribed by Applicable Law to permit the Borrower or the Administrative Agent to determine the withholding or deduction required to be made; and

(d) if a payment made to a Lender under any Loan Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Lender were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Lender shall deliver to the Borrower and the Administrative Agent at the time or times prescribed by law and at such time or times reasonably requested by the Borrower or the Administrative Agent such documentation prescribed by Applicable Law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by the Borrower or the Administrative Agent as may be necessary for the Borrower and the Administrative Agent to comply with their obligations under FATCA and to determine that such Lender has complied with such Lender's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this clause (D), "FATCA" shall include any amendments made to FATCA after the date of this Agreement.

Each Lender agrees that if any form or certification it previously delivered expires or becomes obsolete or inaccurate in any respect, it shall update such form or certification or promptly notify the Borrower and the Administrative Agent in writing of its legal inability to do so.

2.19.8 Treatment of Certain Refunds. If any party determines, in its sole discretion exercised in good faith, that it has received a refund of any Taxes as to which it has been indemnified pursuant to this Section 2.19 (including by the payment of additional amounts pursuant to this Section 2.19), it shall pay to the indemnifying party an amount equal to such refund (but only to the extent of indemnity payments made under this Section with respect to the Taxes giving rise to such refund), net of all out-of-pocket expenses (including Taxes) of such indemnified party and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund). Such indemnifying party, upon the request of such indemnified party, shall repay to such indemnified party the amount paid over pursuant to this Section 2.19.8 (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) in the event that such indemnified party is required to repay such refund to such Governmental Authority. Notwithstanding anything to the contrary in this Section 2.19.8 , in no event will the indemnified party be required to pay any amount to an indemnifying party pursuant to this Section 2.19.8 the payment of which would place the indemnified party in a less favorable net after-Tax position than the indemnified party would have been in if the indemnification payments or additional amounts giving rise to such refund had never been paid. This paragraph shall not be construed to require any indemnified party to make available its Tax returns (or any other information relating to its Taxes that it deems confidential) to the indemnifying party or any other Person.

2.19.9 Survival . Each party's obligations under this Section 2.19 shall survive the resignation or replacement of the Administrative Agent or any assignment of rights by, or the replacement of, a Lender, the termination of the Commitments and the repayment, satisfaction or discharge of all obligations under any Loan Document.

2.20 Compensation . The Borrower will compensate each Lender upon demand for all losses, expenses and liabilities (including, without limitation, any loss, expense or liability incurred by reason of the liquidation or reemployment of deposits or other funds required by such Lender to fund or maintain LIBOR Rate Loans) that such Lender may incur or sustain (i) if for any reason (other than a default by such Lender) a borrowing or continuation of, or conversion into, a LIBOR Rate Loan does not occur on a date specified therefor in a Borrowing Notice or Conversion/Continuation Notice, (ii) if any repayment, prepayment or conversion of any LIBOR Rate Loan occurs on a date other than the last day of an Interest Period applicable thereto (including as a consequence of any assignment made pursuant to Section 2.21.1 or any acceleration of the maturity of the Loans pursuant to ARTICLE VIII), (iii) if any prepayment of any LIBOR Rate Loan is not made on any date specified in a notice of prepayment given by the Borrower or (iv) as a consequence of any other failure by the Borrower to make any payments with respect to any LIBOR Rate Loan when due hereunder. Calculation of all amounts payable to a Lender under this Section 2.20 shall be made as though such Lender had actually funded its relevant LIBOR Rate Loan through the purchase of a eurodollar deposit bearing interest at the LIBOR Rate in an amount equal to the amount of such LIBOR Rate Loan, having a maturity comparable to the relevant Interest Period; provided , however , that each Lender may fund its LIBOR Rate Loans in any manner it sees fit and the foregoing assumption shall be utilized only for the calculation of amounts payable under this Section 2.20 . A certificate (which shall be in reasonable detail) showing the bases for the determinations set forth in this Section 2.20 by any Lender as to any additional amounts payable pursuant to this Section 2.20 shall be submitted by such Lender to the Borrower either directly or through the Administrative Agent. Determinations set forth in any such certificate made in good faith for purposes of this Section 2.20 of any such losses, expenses or liabilities shall be conclusive absent manifest error.

2.21 Mitigation Obligations; Replacement of Lenders.

2.21.1 If any Lender requests compensation under Section 2.18 , or requires the Borrower to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.19 , then such Lender shall (at the request of the Borrower) use reasonable efforts to designate a different Lending Installation for funding or booking its Loans hereunder or to assign its rights and obligations hereunder to another of its offices, branches or affiliates, if, in the judgment of such Lender, such designation or assignment (i) would eliminate or reduce amounts payable pursuant to Sections 2.18 or 2.19 , as the case may be, in the future, and (ii) would not subject such Lender to any unreimbursed cost or expense and would not otherwise be disadvantageous to such Lender. The Borrower hereby agrees to pay all reasonable costs and expenses incurred by any Lender in connection with any such designation or assignment.

2.21.2 If any Lender requests compensation under Section 2.18 , or if the Borrower is required to pay any Indemnified Taxes or additional amounts to any Lender or any Governmental Authority for the account of any Lender pursuant Section 2.19 and, in each case, such Lender has declined or is unable to designate a different Lending Installation in accordance with Section 2.21.1 , or if any Lender is a Defaulting Lender or a Non-Consenting Lender, then the Borrower may, at its sole expense and effort, upon notice to such Lender and the Administrative Agent, require such Lender to assign and delegate, without recourse (in accordance with and subject to the restrictions contained in, and consents required by, Section 12.3), all of its interests, rights (other than its existing rights to payments pursuant to Section 2.18 or 2.19) and obligations under this Agreement and the related Loan Documents to an Eligible Assignee that shall assume such obligations (which assignee may be another Lender, if a Lender accepts such assignment); provided that :

(i) the Borrower shall have paid to the Administrative Agent the assignment fee (if any) specified in Section 12.3.2 ;

(ii) such Lender shall have received payment of an amount equal to the outstanding principal of its Loans and any funded participations in Letters of Credit not refinanced through the Borrowing of Revolving Loans, accrued interest thereon, accrued fees and all other amounts payable to it hereunder and under the other Loan Documents (including any amounts under Section 2.20) from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Borrower (in the case of all other amounts);

(iii) in the case of any such assignment resulting from a request for compensation under Section 2.18 or payments required to be made pursuant to Section 2.19 , such assignment will result in a reduction in such compensation or payments thereafter;

(iv) such assignment does not conflict with Applicable Law; and

(v) in the case of any assignment resulting from a Lender becoming a Non- Consenting Lender, the applicable assignee shall have consented to the applicable amendment, waiver or consent.

A Lender shall not be required to make any such assignment or delegation if, prior thereto, as a result of a waiver by such Lender or otherwise, the circumstances entitling the Borrower to require such assignment and delegation cease to apply.

2.22 Defaulting Lenders.

2.22.1 Defaulting Lender Adjustments . Notwithstanding anything to the contrary contained in this Agreement, if any Lender becomes a Defaulting Lender, then, until such time as such Lender is no longer a Defaulting Lender, to the extent permitted by Applicable Law:

(i) Waivers and Amendments . Such Defaulting Lender’s right to approve or disapprove any amendment, waiver or consent with respect to this Agreement shall be restricted as set forth in the definition of “Required Lenders” and in Section 8.2 .

(ii) Defaulting Lender Waterfall . Any payment of principal, interest, fees or other amounts received by the Administrative Agent for the account of such Defaulting Lender (whether voluntary or mandatory, at maturity, pursuant to or ARTICLE VII otherwise) or received by the Administrative Agent from a Defaulting Lender pursuant to ARTICLE XI shall be applied at such time or times as may be determined by the Administrative Agent as follows:

(a) first , to the payment of any amounts owing by such Defaulting Lender to the Administrative Agent hereunder;

(b) second , to the payment on a pro rata basis of any amounts owing by such Defaulting Lender to any Issuing Bank or the Swingline Lender hereunder;

(c) third , if so determined by the Administrative Agent or requested by any Issuing Bank or the Swingline Lender, to be held as Cash Collateral for future funding obligations of such Defaulting Lender in respect of any participation in any Letter of Credit or Swingline Loan;

(d) fourth , as the Borrower may request (so long as no Unmatured Default or Event of Default exists), to the funding of any Loan in respect of which such Defaulting Lender has failed to fund its portion thereof as required by this Agreement, as determined by the Administrative Agent;

(e) fifth , if so determined by the Administrative Agent and the Borrower, to be held in a non-interest bearing deposit account and released in order to satisfy obligations of such Defaulting Lender to fund Loans under this Agreement;

(f) sixth , to the payment of any amounts owing to the Lenders, the Issuing Banks or the Swingline Lender as a result of any judgment of a court of competent jurisdiction obtained by any Lender, any Issuing Bank or the Swingline Lender against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement;

(g) seventh , so long as no Unmatured Default or Event of Default exists, to the payment of any amounts owing to the Borrower as a result of any judgment of a court of competent jurisdiction obtained by the Borrower against such Defaulting Lender as a result of such Defaulting Lender's breach of its obligations under this Agreement; and

(h) eighth , to such Defaulting Lender or as otherwise directed by a court of competent jurisdiction;

provided that if (x) such payment is a payment of the principal amount of any Loans or any Letter of Credit Exposure in respect of which such Defaulting Lender has not fully funded its appropriate share, and (y) such Loans were made or the related Letters of Credit were issued at a time when the conditions set forth in Section 4.2 were satisfied or waived, such payment shall be applied solely to pay the Loans of, and obligations in respect of Letters of Credit owed to, all non-Defaulting Lenders on a pro rata basis prior to being applied to the payment of any Loans of, or obligations in respect of Letters of Credit owed to, such Defaulting Lender. Any payments, prepayments or other amounts paid or payable to a Defaulting Lender that are applied (or held) to pay amounts owed by a Defaulting Lender or to post Cash Collateral pursuant to this Section 2.22.1(ii) shall be deemed paid to and redirected by such Defaulting Lender, and each Lender irrevocably consents hereto.

(iii) Any Defaulting Lender shall be entitled to receive any Facility Fee for any period during which such Lender is a Defaulting Lender only to the extent allocable to the sum of (1) the outstanding amount of the Revolving Loans funded by it and (2) its Letter of Credit Exposure and Swingline Exposure for which it has provided Cash Collateral pursuant to Section 2.22.3 (and the Borrower shall (A) be required to pay the applicable Issuing Bank and the Swingline Lender the amount of such fee allocable to its Fronting Exposure arising from such Defaulting Lender and (B) not be required to pay the remaining amount of such fee that otherwise would have been required to have been paid to such Defaulting Lender).

(iv) All or any part of such Defaulting Lender's Letter of Credit Exposure and Swingline Exposure shall automatically (effective on the day such Lender becomes a Defaulting Lender) be reallocated among the non-Defaulting Lenders in accordance with their respective Applicable Percentages (calculated without regard to such Defaulting Lender's Commitment) but only to the extent that (x) no Unmatured Default or Event of Default shall have occurred and be continuing (and, unless the Borrower shall have otherwise notified the Administrative Agent at the time, the Borrower shall be deemed to have represented and warranted that such condition is satisfied at such time) and (y) such reallocation does not cause the Credit Exposure of any non-Defaulting Lender to exceed such non-Defaulting Lender's Commitment.

(v) If the reallocation described in Section 2.22.1(iv) cannot, or can only partially, be effected, the Borrower shall, without prejudice to any right or remedy available to it hereunder or under law, within one Business Day following notice by the Administrative Agent, (x) first, prepay Swingline Loans in an amount equal to the Swingline Lenders' Fronting Exposure and (y) second , Cash Collateralize each Issuing Banks' Fronting Exposure in accordance with the procedures set forth in Section 2.22.3 .

2.22.2 If the Borrower, the Administrative Agent, the Issuing Banks and the Swingline Lender agree in writing in their sole discretion that a Defaulting Lender should no longer be deemed to be a Defaulting Lender, the Administrative Agent will so notify the parties hereto, whereupon as of the effective date specified in such notice and subject to any conditions set forth therein (which may include arrangements with respect to any Cash Collateral), such Lender will, to the extent applicable, purchase that portion of outstanding Loans of the other Lenders or take such other actions as the Administrative Agent may determine to be necessary to cause the Revolving Loans and funded and unfunded participations in Letters of Credit and Swingline Loans to be held by the Lenders in accordance with their respective Applicable Percentages (without giving effect to Section 2.22.1(iv)) , whereupon such Lender will cease to be a Defaulting Lender; provided that no adjustments will be made retroactively with respect to fees accrued or payments made by or on behalf of the Borrower while such Lender was a Defaulting Lender; provided further that, except to the extent otherwise expressly agreed by the affected parties, no change hereunder from Defaulting Lender to Lender will constitute a waiver or release of any claim of any party hereunder arising from such Lender's having been a Defaulting Lender.

2.22.3 At any time that there shall exist a Defaulting Lender, within one Business Day upon the request of the Administrative Agent, any Issuing Bank or the Swingline Lender, the Borrower shall deliver to the Administrative Agent Cash Collateral in an amount sufficient to cover all Fronting Exposure (after giving effect to Section 2.22.1(iv) and any Cash Collateral provided by the Defaulting Lender).

(i) All Cash Collateral (other than credit support not constituting funds subject to deposit) shall be maintained in blocked, non-interest bearing deposit accounts with the Administrative Agent. The Borrower, and to the extent provided by any Lender, such Lender, hereby grants to (and subjects to the control of) the Administrative Agent, for the benefit of the Administrative Agent, the Issuing Bank and the Lenders (including the Swingline Lender), and agrees to maintain, a first priority security interest in all such cash, deposit accounts and all balances therein, and all other property so provided as collateral pursuant hereto, and in all proceeds of the foregoing, all as security for the obligations to which such Cash Collateral may be applied pursuant to Section 2.22.3(ii) . If at any time the Administrative Agent determines that Cash Collateral is subject to any right or claim of any Person other than the Administrative Agent as herein provided, or that the total amount of such Cash Collateral is less than the applicable Fronting Exposure and other obligations secured thereby, the Borrower or the relevant Defaulting Lender will, promptly upon demand by the Administrative Agent, pay or provide to the Administrative Agent additional Cash Collateral in an amount sufficient to eliminate such deficiency.

(ii) Notwithstanding anything to the contrary contained in this Agreement, Cash Collateral provided under this Section 2.22 in respect of Letters of Credit shall be held and applied to the satisfaction of the specific Letter of Credit Exposure, obligations to fund participations therein (including, as to Cash Collateral provided by a Defaulting Lender, any interest accrued on such obligation) and other obligations for which the Cash Collateral was so provided, prior to any other application of such Cash Collateral as may be provided for herein.

(iii) Cash Collateral (or the appropriate portion thereof) provided to reduce any Issuing Bank's Fronting Exposure shall no longer be required to be held as Cash Collateral pursuant to this Section following (A) the elimination of the applicable Fronting Exposure (including by the termination of Defaulting Lender status of the applicable Lender), or (B) the determination by the Administrative Agent and each Issuing Bank that there exists excess Cash Collateral; provided that, subject to this Section 2.22 the Person providing Cash Collateral and each Issuing Bank may agree that Cash Collateral shall be held to support future anticipated Fronting Exposure or other obligations and provided further that to the extent that such Cash Collateral was provided by the Borrower, such Cash Collateral shall remain subject to the security interest granted pursuant to the Loan Documents.

2.22.4 So long as any Lender is a Defaulting Lender, (i) the Swingline Lender shall not be required to fund any Swingline Loans unless it is satisfied that it will have no Fronting Exposure after giving effect to such Swingline Loan and (ii) no Issuing Bank shall be required to issue, extend, renew or increase any Letter of Credit unless it is satisfied that it will have no Fronting Exposure after giving effect thereto.

ARTICLE III

LETTERS OF CREDIT

3.1 Issuance . Subject to and upon the terms and conditions herein set forth, so long as no Unmatured Default or Event of Default has occurred and is continuing, each Issuing Bank will, at any time and from time to time on and after the Agreement Date and prior to the earlier of (i) the Letter of Credit Maturity Date and (ii) the Repayment Date, and upon request by the Borrower in accordance with the provisions of Section 3.1 , issue for the account of the Borrower one or more irrevocable standby letters of credit denominated in Dollars and in a form customarily used or otherwise approved by such Issuing Bank (together with all amendments, modifications and supplements thereto, substitutions therefor and renewals and restatements thereof, collectively, the " Letters of Credit "). The Stated Amount of each Letter of Credit shall not be less than such amount as may be acceptable to the applicable Issuing Bank.Notwithstanding the foregoing:

3.1.1 No Letter of Credit shall be issued if, after giving effect to such issuance, (i) the Stated Amount when added to the aggregate Letter of Credit Exposure of the Lenders at such time, would exceed the Letter of Credit Subcommitment, (ii) the Stated Amount when added to the aggregate outstanding Credit Exposure, would exceed the Aggregate Commitments at such time, and (iii) any Lender is at that time a Defaulting Lender, unless the applicable Issuing Bank has entered into an arrangement, including the delivery of Cash Collateral, satisfactory to such Issuing Bank (in its sole discretion) with the Borrower or such Lender to eliminate such Issuing Bank's actual or potential Fronting Exposure (after giving effect to Section 2.22.1(iv)) with respect to the Defaulting Lender arising from either the Letter of Credit then proposed to be issued or that Letter of Credit and all other Letter of Credit Exposure as to which such Issuing Bank has actual or potential Fronting Exposure, as it may elect in its sole discretion;

3.1.2 No Letter of Credit shall be issued that by its terms expires later than the Letter of Credit Maturity Date or, in any event, more than one year after its date of issuance; provided , however , that a Letter of Credit may, if requested by the Borrower, provide by its terms, and on terms acceptable to the applicable Issuing Bank, for renewal for successive periods of one year or less (but not beyond the Letter of Credit Maturity Date), unless and until the applicable Issuing Bank shall have delivered a notice of nonrenewal to the beneficiary of such Letter of Credit;

3.1.3 No Issuing Bank shall be under any obligation to issue any Letter of Credit if, at the time of such proposed issuance, (i) any order, judgment or decree of any Governmental Authority or arbitrator shall purport by its terms to enjoin or restrain such Issuing Bank from issuing such Letter of Credit, or any Applicable Law or any request or directive (whether or not having the force of law) from any Governmental Authority with jurisdiction over such Issuing Bank shall prohibit, or request that such Issuing Bank refrain from, the issuance of letters of credit generally or such Letter of Credit in particular or shall impose upon such Issuing Bank with respect to such Letter of Credit any restriction or reserve or capital requirement (for which such Issuing Bank is not otherwise compensated) not in effect on the Agreement Date, or any unreimbursed loss, cost or expense that was not applicable, in effect or known to such Issuing Bank as of the Agreement Date and that the Issuing Bank in good faith deems material to it, (ii) such Issuing Bank shall have actual knowledge, or shall have received notice from any Lender, prior to the issuance of such Letter of Credit that one or more of the conditions specified in Section 4.1 (if applicable) or Section 4.2 are not then satisfied (or have not been waived in writing as required herein) or that the issuance of such Letter of Credit would violate the provisions of Section 3.1.1 , or (iii) the issuance of such Letter of Credit would violate one or more written policies of such Issuing Bank applicable to letters of credit generally; and

3.1.4 Unless otherwise expressly agreed by the applicable Issuing Bank and the Borrower when a Letter of Credit is issued and subject to applicable laws, performance under Letters of Credit by the applicable Issuing Bank, its correspondents, and the beneficiaries thereof will be governed by the rules of the "International Standby Practices 1998" (or such later revision as may be published by the Institute of International Banking Law & Practice on any date any Letter of Credit may be issued) and to the extent not inconsistent therewith, the governing law of this Agreement.

3.2 Notices . Whenever the Borrower desires the issuance of a Letter of Credit, the Borrower will give the applicable Issuing Bank written notice with a copy to the Administrative Agent not later than 11:00 a.m. three Business Days (or such shorter period as is acceptable to the Issuing Bank in any given case) prior to the requested date of issuance thereof. Each such notice (each, a " Letter of Credit Notice ") shall be irrevocable, shall be given in the form of Exhibit 3.2 and shall specify (i) the requested date of issuance, which shall be a Business Day, (ii) the requested Stated Amount and expiry date of the Letter of Credit, and (iii) the name and address of the requested beneficiary or beneficiaries of the Letter of Credit. The Borrower will also complete any application procedures and documents reasonably required by the applicable Issuing Bank in connection with the issuance of any Letter of Credit. Upon its issuance of any Letter of Credit, the applicable Issuing Bank will promptly notify the Administrative Agent of such issuance, and the Administrative Agent will give prompt notice thereof to each Lender. The renewal or extension of any outstanding Letter of Credit shall, for purposes of this Article III, be treated in all respects as the issuance of a new Letter of Credit.

3.3 Participations . Immediately upon the issuance of any Letter of Credit, the Issuing Bank shall be deemed to have sold and transferred to each Lender, and each Lender shall be deemed irrevocably and unconditionally to have purchased and received from the Issuing Bank, without recourse or warranty, an undivided interest and participation, of its Applicable Percentage of such Letter of Credit, each drawing made thereunder and the obligations of the Borrower under this Agreement with respect thereto and any Collateral or other security therefor or guaranty pertaining thereto; provided , however , that the LC Fee shall be payable directly to the Issuing Bank as provided therein, and the other Lenders shall have no right to receive any portion thereof. In consideration and in furtherance of the foregoing, each Lender hereby absolutely and unconditionally agrees to pay to the Administrative Agent, for the account of the Issuing Bank, such Lender's Applicable Percentage of each Reimbursement Obligation not reimbursed by the Borrower on the date due as provided in Section 3.4 or through the Borrowing of Revolving Loans as provided in Section 3.5 (because the conditions set forth in Section 4.2 cannot be satisfied, or for any other reason), or of any reimbursement payment required to be refunded to the Borrower for any reason. Upon any change in the Commitments of any of the Lenders pursuant to Section 2.5.2 or Section 12.3 , with respect to all outstanding Letters of Credit and Reimbursement Obligations there shall be an automatic adjustment to the participations pursuant to this Section 3.3 to reflect the new Applicable Percentages of the assigning Lender and the assignee. Each Lender's obligation to make payment to the Issuing Banks pursuant to this Section 3.3 shall be absolute and unconditional and shall not be affected by any circumstance whatsoever, including the termination of the Commitments or the existence of any Unmatured Default or Event of Default, and each such payment shall be made without any offset, abatement, reduction or withholding whatsoever.

3.4 Reimbursement . The Borrower hereby agrees to reimburse the applicable Issuing Bank by making payment to the Administrative Agent, for the account of such Issuing Bank, in immediately available funds, for any payment made by such Issuing Bank under any Letter of Credit issued by it (each such amount so paid until reimbursed, together with interest thereon payable as provided hereinbelow, a " Reimbursement Obligation ") immediately upon, and in any event on the same Business Day as, the making of such payment by such Issuing Bank (the " Honor Date "), provided that any such Reimbursement Obligation shall be deemed timely satisfied (but nevertheless subject to the payment of interest thereon as provided herein below) if satisfied pursuant to a borrowing of Revolving Loans made on the date of such payment by the Issuing Bank, as set forth more completely in Section 3.5), together with interest on the amount so paid by such Issuing Bank, to the extent not reimbursed prior to 2:00 p.m. on the Honor Date, for the period from the Honor Date to the date the Reimbursement Obligation created thereby is satisfied, at the Alternate Base Rate plus the Applicable Margin plus 2% per annum as in effect from time to time during such period, such interest also to be payable on demand. Each Issuing Bank will provide the Administrative Agent and the Borrower with prompt notice of any payment or disbursement made or to be made under any Letter of Credit issued by it, although the failure to give, or any delay in giving, any such notice shall not release, diminish or otherwise affect the Borrower's obligations under this Section 3.4 or any other provision of this Agreement. The Administrative Agent will promptly pay to the applicable Issuing Bank any such amounts received by it under this Section 3.4 .

3.5 Payment by Revolving Loans .

3.5.1 In the event that any Issuing Bank makes any payment under any Letter of Credit and the Borrower shall not have timely satisfied in full its Reimbursement Obligation to such Issuing Bank pursuant to Section 3.4 , the Borrower shall be deemed to have requested a Borrowing of Base Rate Loans to be disbursed on the Honor Date in an amount equal to the Reimbursement Obligation (the " Unreimbursed Amount "), without regard to the minimum and multiples for the principal amount of Base Rate Loans, but subject to the amount of the unutilized portion of the Aggregate Commitments and the conditions set forth in Section 4.2 (other than the delivery of a Notice of Borrowing). Any notice given by the applicable Issuing Bank or the Administrative Agent pursuant to this Section 3.5.1 may be given by telephone if immediately confirmed in writing; provided that the lack of such an immediate confirmation shall not affect the conclusiveness or binding effect of such notice.

3.5.2 Each Lender shall upon any notice pursuant to Section 3.5.1 make funds available (and the Administrative Agent may apply Cash Collateral provided for this purpose) for the account of the applicable Issuing Bank in an amount equal to its Applicable Percentage of the Unreimbursed Amount not later than 1:00 p.m. on the Business Day specified in such notice by the Administrative Agent, whereupon, subject to the provisions of Section 3.5.3 , each Lender that so makes funds available shall be deemed to have made a Base Rate Loan to the Borrower in such amount. The Administrative Agent shall remit the funds so received to the applicable Issuing Bank.

3.5.3 With respect to any Unreimbursed Amount that is not fully refinanced by a borrowing of Base Rate Loans because the conditions set forth in Section 4.2 cannot be satisfied or for any other reason, each Lender shall fund its risk participation in such Letter of

Credit in the amount of its Applicable Percentage of the Unreimbursed Amount that is not so refinanced, which funded risk participation shall be due and payable on demand (together with interest) and shall bear interest at the Overdue Rate.

3.5.4 Until each Lender funds its Base Rate Loan or risk participation pursuant to this Section 3.5 to reimburse the applicable Issuing Bank for any amount drawn under any Letter of Credit, interest in respect of such Lender's Applicable Percentage of such amount shall be solely for the account of the applicable Issuing Bank.

3.5.5 Each Lender's obligation to make Base Rate Loans or to fund its risk participation to reimburse the applicable Issuing Bank for amounts drawn under Letters of Credit, as contemplated by this Section 3.5 , shall be absolute and unconditional and shall not be affected by any circumstance, including (A) any setoff, counterclaim, recoupment, defense or other right which such Lender may have against such Issuing Bank, the Borrower or any other Person for any reason whatsoever; (B) the occurrence or continuance of an Unmatured Default or Event of Default, or (C) any other occurrence, event or condition, whether or not similar to any of the foregoing; provided , however , that each Lender's obligation to make Base Rate Loans pursuant to this Section 3.5 is subject to the conditions set forth in Section 4.2 (other than delivery by the Borrower of a Notice of Borrowing). No such making of a Base Rate Loan or funding of risk participation shall relieve or otherwise impair the obligation of the Borrower to reimburse the applicable Issuing Bank for the amount of any payment made by such Issuing Bank under any Letter of Credit, together with interest as provided herein.

3.5.6 If any Lender fails to make available to the Administrative Agent for the account of the applicable Issuing Bank any amount required to be paid by such Lender pursuant to the foregoing provisions of this Section 3.5 by the time specified in Section 3.5.2 , then, without limiting the other provisions of this Agreement, the applicable Issuing Bank shall be entitled to recover from such Lender (acting through the Administrative Agent), on demand, such amount with interest thereon for the period from the date such payment is required to the date on which such payment is immediately available to such Issuing Bank at a rate per annum equal to the greater of the Federal Funds Rate and a rate determined by such Issuing Bank in accordance with banking industry rules on interbank compensation, plus any administrative, processing or similar fees customarily charged by such Issuing Bank in connection with the foregoing. If such Lender pays such amount (with interest and fees as aforesaid), the amount so paid shall constitute such Lender's Base Rate Loan included in the relevant borrowing or funded risk participation, as the case may be. A certificate of the applicable Issuing Bank submitted to any Lender (through the Administrative Agent) with respect to any amounts owing under this Section 3.5.6 shall be conclusive absent manifest error.

3.6 Payment to Lenders . Whenever any Issuing Bank receives a payment in respect of a Reimbursement Obligation as to which the Administrative Agent has received, for the account of such Issuing Bank, any payments from the Lenders pursuant to Section 3.5, such Issuing Bank will promptly pay to the Administrative Agent, and the Administrative Agent will promptly pay to each Lender that has paid its ratable share thereof, in immediately available funds, an amount equal to such Lender's ratable share (based on the proportionate amount funded by such Lender to the aggregate amount funded by all Lenders) of such Reimbursement Obligation.

3.7 Obligations Absolute . The Reimbursement Obligations of the Borrower shall be irrevocable, shall remain in effect until the Issuing Banks shall have no further obligations to make any payments or disbursements under any circumstances with respect to any Letter of Credit, and shall be absolute and unconditional, shall not be subject to counterclaim, setoff or other defense or any other qualification or exception whatsoever and shall be made in accordance with the terms and conditions of this Agreement under all circumstances, including, without limitation, any of the following circumstances:

3.7.1 Any lack of validity or enforceability of this Agreement, any of the other Loan Documents or any documents or instruments relating to any Letter of Credit;

3.7.2 Any change in the time, manner or place of payment of, or in any other term of, all or any of the Obligations in respect of any Letter of Credit or any other amendment, modification or waiver of or any consent to departure from any Letter of Credit or any documents or instruments relating thereto, in each case whether or not the Borrower has notice or knowledge thereof;

3.7.3 The existence of any claim, setoff, defense or other right that the Borrower may have at any time against a beneficiary named in a Letter of Credit, any transferee of any Letter of Credit (or any Person for whom any such transferee may be acting), the Administrative Agent, any Issuing Bank, any Lender or other Person, whether in connection with this Agreement, any Letter of Credit, the transactions contemplated hereby or any unrelated transactions (including any underlying transaction between the Borrower and the beneficiary named in any such Letter of Credit);

3.7.4 Any draft, certificate or any other document presented under the Letter of Credit proving to be forged, fraudulent, invalid or insufficient in any respect or any statement therein being untrue or inaccurate in any respect (provided that such draft, certificate or other document appears on its face to comply with the terms of such Letter of Credit), any errors, omissions, interruptions or delays in transmission or delivery of any messages, by mail, facsimile or otherwise, or any errors in translation or in interpretation of technical terms;

3.7.5 Any defense based upon the failure of any drawing under a Letter of Credit to conform to the terms of the Letter of Credit (provided that any draft, certificate or other document presented pursuant to such Letter of Credit appears on its face to comply with the terms thereof), any nonapplication or misapplication by the beneficiary or any transferee of the proceeds of such drawing or any other act or omission of such beneficiary or transferee in connection with such Letter of Credit;

3.7.6 The exchange, release, surrender or impairment of any collateral or other security for the Obligations;

3.7.7 The occurrence of any Unmatured Default or Event of Default; or

3.7.8 Any other circumstance or event whatsoever, including, without limitation, any other circumstance that might otherwise constitute a defense available to, or a discharge of, the Borrower or a guarantor.

Any action taken or omitted to be taken by any Issuing Bank under or in connection with any Letter of Credit, if taken or omitted in the absence of gross negligence or willful misconduct, shall be binding upon the Borrower and each Lender and shall not create or result in any liability of such Issuing Bank to the Borrower or any Lender. It is expressly understood and agreed that, for purposes of determining whether a wrongful payment under a Letter of Credit resulted from any Issuing Bank's gross negligence or willful misconduct, (i) such Issuing Bank's acceptance of documents that appear on their face to comply with the terms of such Letter of Credit, without responsibility for further investigation, regardless of any notice or information to the contrary, (ii) such Issuing Bank's exclusive reliance on the documents presented to it under such Letter of Credit as to any and all matters set forth therein, including the amount of any draft presented under such Letter of Credit, whether or not the amount due to the beneficiary thereunder equals the amount of such draft and whether or not any document presented pursuant to such Letter of Credit proves to be insufficient in any respect (so long as such document appears on its face to comply with the terms of such Letter of Credit), and whether or not any other statement or any other document presented pursuant to such Letter of Credit proves to be forged or invalid or any statement therein proves to be inaccurate or untrue in any respect whatsoever, and (iii) any noncompliance in any immaterial respect of the documents presented under such Letter of Credit with the terms thereof shall, in each case, be deemed not to constitute gross negligence or willful misconduct of such Issuing Bank.

3.8 Cash Collateral Account . At any time and from time to time (i) after the occurrence and during the continuance of an Event of Default, the Administrative Agent may, and at the direction or with the consent of the Required Lenders shall, require the Borrower to deliver to the Administrative Agent such additional amount of cash as is equal to 102% of the aggregate Stated Amount of all Letters of Credit at any time outstanding (whether or not any beneficiary under any Letter of Credit shall have drawn or be entitled at such time to draw thereunder) and (ii) in the event of a prepayment under Section 2.5.1 , the Administrative Agent will retain such amount as may then be required to be retained, such amounts in each case under clauses (i) and (ii) above to be held by the Administrative Agent in a cash collateral account (the " Cash Collateral Account "). The Borrower hereby grants to the Administrative Agent, for the benefit of the Issuing Bank and the Lenders, a Lien upon and security interest in the Cash Collateral Account and all amounts held therein from time to time as security for Letter of Credit Exposure, and for application to the Borrower's Reimbursement Obligations as and when the same shall arise. The Administrative Agent shall have exclusive dominion and control, including the exclusive right of withdrawal, over such account. Other than any interest on the investment of such amounts in Cash Equivalents, which investments shall be made at the direction of the Borrower (unless an Unmatured Default or Event of Default shall have occurred and be continuing, in which case the determination as to investments shall be made at the option and in the discretion of the Administrative Agent), amounts in the Cash Collateral Account shall not bear interest. Interest and profits, if any, on such investments shall accumulate in such account. In the event of a drawing, and subsequent payment by any Issuing Bank, under any Letter of Credit at any time during which any amounts are held in the Cash Collateral Account, the Administrative Agent will deliver to such Issuing Bank an amount equal to the Reimbursement Obligation created as a result of such payment (or, if the amounts so held are less than such Reimbursement Obligation, all of such amounts) to reimburse such Issuing Bank therefor. Any amounts remaining in the Cash Collateral Account (including interest) after the expiration of all Letters of Credit and reimbursement in full of the Issuing Banks for all of its obligations thereunder shall be held by the Administrative Agent, for the benefit of the Borrower, to be applied against the Obligations in such order and manner as the Administrative Agent may direct.

3.9 The Issuing Bank . The Issuing Banks shall act on behalf of the Lenders with respect to any Letters of Credit issued by it and the documents associated therewith, and the Issuing Banks shall have all of the rights, benefits and immunities (a) provided to the Administrative Agent in ARTICLE X with respect to any acts taken or omissions suffered by it in connection with Letters of Credit issued by it or proposed to be issued by it and any documents pertaining to such Letters of Credit as fully as if the term "Administrative Agent" as used in ARTICLE X included the Issuing Banks with respect to such acts or omissions, and (b) as additionally provided herein with respect to the Issuing Banks.

3.10 Effectiveness . Notwithstanding any termination of the Commitments or repayment of the Loans, or both, the obligations of the Borrower under this ARTICLE III shall remain in full force and effect until the Issuing Banks and the Lenders shall have no further obligations to make any payments or disbursements under any circumstances with respect to any Letter of Credit.

ARTICLE IV

CONDITIONS PRECEDENT

4.1 Conditions to Agreement Date . The obligation of each Lender to make Loans and the obligation of the Issuing Banks to issue Letters of Credit hereunder on the Agreement Date, is subject to the satisfaction of the following conditions precedent:

(a) The Administrative Agent shall have received the following, each dated as of the Agreement Date (unless otherwise specified) and in such number of copies as the Administrative Agent shall have requested:

(1) Fully executed counterparts of this Agreement from the Borrower, each Lender, the Issuing Bank, the Swingline Lender and the Administrative Agent.

(2) Copies of the articles or certificate of incorporation of the Borrower, together with all amendments thereto, and a certificate of good standing, each certified by the appropriate governmental officer or the secretary of the Borrower in its jurisdictions of incorporation.

(3) Copies, certified by the Secretary or Assistant Secretary of the Borrower, of its by-laws and of its Board of Directors' resolutions and of resolutions or actions of any other body authorizing (i) the execution of the Loan Documents to which the Borrower is a party and (ii) borrowings hereunder by the Borrower in an aggregate amount up to $350,000,000.

(4) An incumbency certificate, executed by the Secretary or Assistant Secretary of the Borrower, which shall identify by name and title and

bear the signatures of the Authorized Officers and any other officers of the Borrower authorized to sign the Loan Documents, upon which certificate the Administrative Agent and the Lenders shall be entitled to rely until informed of any change in writing by the Borrower.

(5) A certificate, signed by the chief financial officer of the Borrower, stating that the conditions specified in Section 4.2(b) and (c) have been satisfied.

(6) A written opinion of the Borrower's counsel, addressed to the Lenders substantially in the form of Exhibit 4.1(a)(6) .

(7) Any Notes requested by a Lender pursuant to Section 2.11 payable to the order of each such requesting Lender.

(8) Evidence that the Existing Credit Agreement has been or concurrently with the Agreement Date is being terminated.

(9) Evidence satisfactory to the Administrative Agent of any required Governmental Approvals or consents regarding this Agreement.

(b) The Borrower shall have paid (i) to the Arrangers, the fees required under the Fee Letters to be paid to them on the Agreement Date, (ii) to the Administrative Agent, the initial payment of the annual administrative fee described in the Administrative Fee Letter, and (iii) all other fees and reasonable expenses of the Arrangers, the Administrative Agent and the Lenders required hereunder or under any other Loan Document to be paid on or prior to the Agreement Date (including reasonable fees and expenses of counsel) in connection with this Agreement and the other Loan Documents.

Without limiting the generality of the provisions of the last paragraph of Section 10.3 , for purposes of determining compliance with the conditions specified in this Section 4.1 , each Lender that has signed this Agreement shall be deemed to have consented to, approved or accepted or to be satisfied with, each document or other matter required thereunder to be consented to or approved by or acceptable or satisfactory to a Lender unless the Administrative Agent shall have received notice from such Lender prior to the proposed Agreement Date specifying its objection thereto.

4.2 Conditions to All Credit Extensions . The Lenders shall not be required to make any Loan, including the initial Loan, and no Issuing Bank shall be required to issue any Letter of Credit, unless on the applicable date of the requested extension of credit:

(a) The Borrower shall have furnished to the Administrative Agent, with sufficient copies for each Lender, a certificate dated such date of the requested extension of credit and signed by an Authorized Officer of the Borrower, stating that after taking in account the making of such Loan or issuance of such Letter of Credit, and the repayment of any outstanding obligations of the Borrower with respect to commercial paper with the proceeds of such Loan, if applicable, the Borrower will not have exceeded the maximum aggregate principal amount that the Borrower is entitled to borrow from financial institutions or receive from the sale of commercial paper under Board of Directors' resolutions of the Borrower.

(b) There exists no Event of Default or Unmatured Default.

(c) The representations and warranties contained in Article V (other than, after the Agreement Date, the representations and warranties set forth in Sections 5.2(b), 5.3, 5.11(a), 5.11(b), 5.11(c), 5.11(f), 5.11(g), 5.11(h) and 5.11(i)) are true and correct as of such date of the requested extension of credit except to the extent any such representation or warranty is stated to relate solely to an earlier date, in which case such representation or warranty shall have been true and correct on and as of such earlier date.

(d) All legal matters incident to such extension of credit shall be satisfactory to the Lenders and their counsel (including, without limitation, evidence satisfactory to the Administrative Agent of any required Governmental Approvals or consents regarding such extension of credit).

Each request for an extension of credit shall constitute a representation and warranty by the Borrower that the conditions contained in Sections 4.2(a), (b) and (c) have been satisfied. Any Lender may require a duly completed compliance certificate in substantially the form of Exhibit 4.2 (a " Compliance Certificate ") as a condition to making a Loan.

ARTICLE V

REPRESENTATIONS AND WARRANTIES

The Borrower represents and warrants to the Lenders that:

5.1 Corporate Existence . Each of the Borrower and its Material Subsidiaries: (a) is a corporation duly organized and validly existing under the laws of the jurisdiction of its incorporation; (b) has all requisite corporate power, and has all material governmental licenses, authorizations, consents and approvals, necessary to own its assets and carry on its business as now being or as proposed to be conducted; and (c) is qualified to do business in all jurisdictions in which the nature of the business conducted by it makes such qualification necessary and where failure so to qualify would have a Material Adverse Effect.

5.2 Financial Condition .

(a) The consolidated balance sheet and statement of consolidated capitalization of the Borrower and its consolidated Subsidiaries, if any, as at September 30, 2011 and the related consolidated statements of income, cash flows, common stockholders' equity and income taxes of the Borrower and its consolidated Subsidiaries, if any, for the fiscal year ended on September 30, 2011, with the opinion thereon of Deloitte & Touche LLP, and the unaudited consolidated balance sheet of the Borrower and its consolidated Subsidiaries, if any, as at December 31, 2011 and the related consolidated statements of income and cash flows of the Borrower and its consolidated Subsidiaries, if any, for the applicable three-month period ended on such date, heretofore furnished to each of the Lenders are complete and correct and fairly present the consolidated financial condition of the Borrower and its consolidated Subsidiaries, if any, as at said date and the results of their operations for the fiscal year and the applicable three-month period ended on said dates (subject, in the case of financial statements as at December 31, 2011 to normal year-end audit adjustments), all in accordance with GAAP and practices applied on a consistent basis. Neither the Borrower nor any of its Material Subsidiaries had on said dates any material contingent liabilities, liabilities for taxes, unusual forward or long-term commitments or unrealized or anticipated losses from any unfavorable commitments, except as referred to or reflected or provided for in said balance sheets as at said dates.

(b) Since September 30, 2011, there has been no material adverse change in the consolidated financial condition or operations, or the prospects or business taken as a whole, of the Borrower and its consolidated Subsidiaries, if any, from that set forth in said financial statements as at said date.

5.3 Litigation . Other than as set out in Schedule 5.3 hereto, there are no legal or arbitral proceedings or any proceedings by or before any Governmental Authority, now pending or (to the knowledge of the Borrower) threatened against the Borrower or any of its Material Subsidiaries as to which there is a reasonable possibility of an adverse determination and which, if adversely determined, could have a Material Adverse Effect during the term of this Agreement.

5.4 No Breach . None of the execution and delivery of this Agreement and the Notes, the consummation of the transactions herein contemplated and compliance with the terms and provisions hereof will conflict with or result in a breach of, or require any consent under, the charter or by-laws of the Borrower, or any Applicable Law or regulation, or any order, writ, injunction or decree of any court or governmental authority or agency, or any agreement or instrument to which the Borrower or its Material Subsidiaries is a party or by which it is bound or to which it is subject or which is applicable to it, or constitute a default under any such agreement or instrument, or result in the creation or imposition of any Lien upon any of the revenues or assets of the Borrower or any of its Material Subsidiaries pursuant to the terms of any such agreement or instrument.

5.5 Corporate Action . The Borrower has all necessary corporate power and authority to execute, deliver and perform its obligations under this Agreement and the Notes and to consummate the transactions herein contemplated, and the execution, delivery and performance of this Agreement and the Notes, and the consummation of the transactions herein contemplated, by the Borrower have been duly authorized by all necessary corporate action on its part; and this Agreement has been duly and validly executed and delivered by the Borrower and constitutes, and each of the Notes when executed and delivered for value will constitute, its legal, valid and binding obligation, enforceable in accordance with its terms.

5.6 Regulatory Approval . No consent, approval, authorization or other action by, notice to, or registration or filing with, any Governmental Authority or other Person is or will be required as a condition to or otherwise in connection with the due execution, delivery and performance by the Borrower of this Agreement or any of the other Loan Documents to which it is or will be a party or the legality, validity or enforceability hereof or thereof, other than consents, authorizations and filings that have been (or on or prior to the Agreement Date will have been) made or obtained and that are (or on the Agreement Date will be) in full force and effect, which consents, authorizations and filings are listed on Schedule 5.6 .

5.7 Regulations U and X . The Borrower is not engaged in the business of extending credit for the purpose of purchasing or carrying margin stock, and no proceeds of any Loans will be used for a purpose which violates, or would be inconsistent with, F.R.S. Board Regulation U or X, or any official rulings on or interpretations of such regulations. Terms for which meanings are provided in Regulation U or Regulation X or any regulations substituted therefor, as from time to time in effect, are used in this Section 5.7 with such meanings.

5.8 Pension and Welfare Plans . The Borrower is in compliance with the applicable provisions of ERISA. During the twelve consecutive-month period prior to the date of the execution and delivery of this Agreement and prior to the date of any borrowing hereunder, no steps have been taken to terminate or completely or partially withdraw from any Pension Plan, and no contribution failure has occurred with respect to any Pension Plan sufficient to give rise to a Lien under section 302 (f) of ERISA. No condition exists or event or transaction has occurred with respect to any Pension Plan which might result in the incurrence by the Borrower or any member of the Controlled Group of any material liability, fine or penalty or which could reasonably be expected to have a Material Adverse Effect. Except as disclosed in Schedule 5.8 (" Employee Benefit Plans "), neither the Borrower nor any member of the Controlled Group has any contingent liability with respect to any post-retirement benefit under a Welfare Plan, other than liability for continuation coverage described in Part 6 of Title I of ERISA.

5.9 Accuracy of Information . All factual information heretofore or contemporaneously furnished by or on behalf of the Borrower in writing to the Administrative Agent or any Lender for purposes of or in connection with this Agreement or any transaction contemplated hereby is, and all other such factual information hereafter furnished by or on behalf of the Borrower to the Administrative Agent or any Lender will be, true and accurate in every material respect on the date as of which such information is dated or certified and as of the date of execution and delivery of this Agreement by the Administrative Agent and such Lender, and such information is not, or shall not be, as the case may be, incomplete by omitting to state any material fact necessary to make such information not misleading.

5.10 Taxes . United States Federal income tax returns of the Borrower and those of its Subsidiaries that have filed their returns on a consolidated basis with the Borrower have been examined and/or closed through the fiscal year of the Borrower ended September 30, 2011. The Borrower and its Subsidiaries have filed all United States Federal income tax returns and all other material tax returns which are required to be filed by them and have paid all taxes due pursuant to such returns or pursuant to any assessment received by the Borrower or any of its Subsidiaries. The charges, accruals and reserves on the books of the Borrower and its Subsidiaries in respect of taxes and other governmental charges are, in the opinion of the Borrower, adequate.

5.11 Environmental Warranties . Except as previously disclosed in the SEC Disclosure Documents or on Schedule 5.11 :

(a) all facilities and property (including underlying groundwater) owned, operated or leased by the Borrower or any of its Subsidiaries are in material compliance with all Environmental Laws, except for such instances of noncompliance as are unlikely, singly or in the aggregate, to have a Material Adverse Effect;

(b) there have been no past, and there are no pending or threatened:

(1) claims, complaints, notices or requests for information received by the Borrower or any of its Subsidiaries with respect to any alleged violation of any Environmental Law or,

(2) complaints, notices or inquiries to the Borrower or any of its Subsidiaries regarding potential liability under any Environmental Law;

except as are unlikely, singly or in the aggregate, to have a Material Adverse Effect;

(c) to the Borrower's knowledge, there have been no Releases of Hazardous Materials at, on or under any property now or previously owned, operated or leased by the Borrower or any of its Subsidiaries that, singly or in the aggregate, are reasonably likely to have a Material Adverse Effect during the term of this Agreement;

(d) the Borrower and its Subsidiaries have been issued and are in material compliance with all permits, certificates, approvals, licenses and other authorizations relating to environmental matters and necessary for their businesses;

(e) no property now or previously owned, operated or leased by the Borrower or any of its Subsidiaries is listed or proposed for listing (with respect to owned property only) on the National Priorities List pursuant to CERCLA or on any similar state list of sites requiring investigation or cleanup;

(f) to the Borrower's knowledge, there are no underground storage tanks, active or abandoned, including petroleum storage tanks, on or under any property now or previously owned, operated or leased by the Borrower or any of its Subsidiaries that, singly or in aggregate, could have a Material Adverse Effect during the term of this Agreement;

(g) to the Borrower's knowledge, neither Borrower nor any of its Subsidiaries has directly transported or directly arranged for the transportation of any Hazardous Material to any location which is listed or proposed for listing on the National Priorities List pursuant to CERCLA, on the CERCLIS or on any similar state list or which is the subject of Federal, state or local enforcement actions or other investigations which may lead to material claims against the Borrower or such Subsidiary for any remedial work, damage to natural resources or personal injury, including claims under CERCLA that, singly or in the aggregate, are likely to have a Material Adverse Effect during the term of this Agreement;

(h) there are no polychlorinated biphenyls or friable asbestos present at any property now or previously owned, operated or leased by the Borrower or any of its Subsidiaries that, singly or in the aggregate, could have a Material Adverse Effect during the term of this Agreement; and

(i) no conditions exist at, on or under any property now or previously owned or leased by the Borrower or any of its Subsidiaries which, with the passage of time, or the giving of notice or both, would give rise to liability under any Environmental Law, which would have a Material Adverse Effect during the term of this Agreement.

5.12 Investment Company Act . Neither the Borrower nor any of its Subsidiaries is an “investment company” or a company “controlled” by an “investment company” within the meaning of the Investment Company Act of 1940, as amended.

5.13 OFAC; Anti-Terrorism Laws .

(a) Neither the Borrower nor any of it Subsidiaries (i) is a Sanctioned Person, (ii) has more than 10% of its assets in Sanctioned Countries, or (iii) derives more than 10% of its operating income from investments in, or transactions with, Sanctioned Persons or Sanctioned Countries. No part of the proceeds of any Loan hereunder will be used directly or indirectly to fund any operations in, finance any investments or activities in or make any payments to, a Sanctioned Person or a Sanctioned Country.

(b) Neither the making of the Loans hereunder nor the use of the proceeds thereof will violate the PATRIOT Act, the Trading with the Enemy Act, as amended, the Foreign Corrupt Practices Act or any of the foreign assets control regulations of the United States Treasury Department (31 CFR, Subtitle B, Chapter V, as amended) or any enabling legislation or executive order relating thereto. The Credit Parties are in compliance in all material respects with the PATRIOT Act.

ARTICLE VI

COVENANTS

During the term of this Agreement, unless the Required Lenders shall otherwise consent in writing:

6.1 Financial Statements . The Borrower shall deliver to the Administrative Agent (and, in the case of clauses (e), (f) and (g) below, to each of the Lenders):

(a) as soon as available and in any event within 50 days after the end of each of the first three fiscal quarterly periods of each fiscal year of the Borrower, a consolidated statement of income of the Borrower and its consolidated Subsidiaries for such period and for the period from the beginning of the respective fiscal year to the end of such period, and a consolidated statement of cash flows for the period from the beginning of the respective fiscal year to the end of such period, the related consolidated balance sheet as at the end of such period, all in reasonable detail and prepared in accordance with GAAP (subject to the absence of notes required by GAAP and subject to normal year-end adjustments) applied on a basis consistent with that of the preceding quarter or containing disclosure of the effect on the financial condition or results of operations of any change in the application of accounting principles and practices during such quarter, accompanied by a certificate of a senior financial officer of the Borrower, which certificate shall state that said financial statements fairly present the consolidated financial condition and results of operations of the Borrower and its consolidated Subsidiaries in accordance with GAAP, consistently applied, as at the end of, and for, such period (subject to normal year-end audit adjustments);

(b) as soon as available and in any event within 95 days after the end of each fiscal year of the Borrower, consolidated statements of income, common stockholders' equity, cash flows, and income taxes of the Borrower and its consolidated Subsidiaries for such year and the related consolidated balance sheet and statement of capitalization at the end of such year, setting forth in each case in comparative form the corresponding figures for the preceding fiscal year, all in reasonable detail and prepared in accordance with GAAP (subject to the absence of notes required by GAAP and subject to normal year-end adjustments) applied on a basis consistent with that of the preceding quarter or containing disclosure of the effect on the financial condition or results of operations of any change in the application of accounting principles and practices during such quarter, and accompanied by an opinion thereon of independent certified public accountants of recognized national standing, which opinion shall state, without material qualification, that said financial statements fairly present the consolidated financial position and results of operations and cash flows of the Borrower and its consolidated Subsidiaries as at the end of, and for, such fiscal year;

(c) promptly upon their becoming available, notification of the filing of all registration statements, regular periodic reports, if any, and SEC Disclosure Documents which the Borrower shall have filed with the Securities and Exchange Commission (or any governmental agency substituted therefor) or any national securities exchange;

(d) promptly upon the mailing thereof to the shareholders of the Borrower generally, copies, if not publicly available, or notification of mailing, of all financial statements, reports and proxy statements so mailed;

(e) promptly after the Borrower knows or has reason to know that any Event of Default or Unmatured Default has occurred, a notice of such Event of Default or Unmatured Default, describing the same in reasonable detail, and indicating what action is being undertaken with respect to such Event of Default or Unmatured Default;

(f) immediately upon becoming aware of the institution of any steps by the Borrower or any other Person to terminate any Pension Plan or the complete or partial withdrawal from any Pension Plan by the Borrower or any member of its Controlled Group, or the failure to make a required contribution to any Pension Plan if such failure is sufficient to give rise to a Lien under section 302(f) of ERISA, or the taking of any action with respect to a Pension Plan which could result in the requirement that the Borrower furnish a bond or other security to the PBGC or such Pension Plan, or the occurrence of any event with respect to any Pension Plan which could result in the incurrence by the Borrower of any material liability, fine or penalty, or any material increase in the contingent liability of the Borrower with respect to any post-retirement Welfare Plan benefit, notice thereof and copies of all documentation relating thereto; and

(g) from time to time such other information regarding the business, affairs or financial condition of the Borrower or any of its Subsidiaries as any Lender or the Administrative Agent may reasonably request.

The Borrower will furnish to the Administrative Agent, at the time it furnishes each set of financial statements pursuant to clause (a) or (b) above, a Compliance Certificate, executed by an Authorized Officer of the Borrower.

Information required to be delivered pursuant to clause (a), (b) or (c) above shall be deemed to have been delivered on the date on which (i) such information is actually delivered to the Administrative Agent for distribution to the Lenders or (ii) such information (x) has been posted by the Borrower on the Borrower's website at www.wglholdings.com, or at www.sec.gov or www.ferc.gov and (y) the Borrower provides notice to the Lenders that such information is available and specifies one or more of the above websites on which such information is located. At the request of the Administrative Agent, the Borrower will provide, by electronic mail, electronic versions of all documents containing such information.

6.2 Litigation. The Borrower shall promptly give to each Lender notice of all legal or arbitral proceedings, and of all proceedings before any governmental or regulatory authority or agency, affecting the Borrower or its Material Subsidiaries, except proceedings as to which there is no reasonable possibility of an adverse determination or which, if adversely determined, would not have a Material Adverse Effect during the term of this Agreement.

6.3 Corporate Existence, Compliance with Laws, Taxes, Examination of Books, Insurance, etc. The Borrower shall, and shall cause each of its Material Subsidiaries to: preserve and maintain its corporate existence and all of its material rights, privileges and franchises if failure to maintain such existence, rights, privileges or franchises would materially and adversely affect the financial condition or operations of, or the business taken as a whole, of the Borrower and its Subsidiaries; comply with the requirements of all Applicable Laws, rules, regulations and orders of governmental or regulatory authorities if failure to comply with such requirements would materially and adversely affect the financial condition or operations of, or the business taken as a whole, of the Borrower and its Subsidiaries; pay and discharge all taxes, assessments and governmental charges or levies imposed on it or on its income or profits or on any of its property prior to the date on which penalties attach thereto, except for any such tax, assessment, charge or levy the payment of which is being contested in good faith and by proper proceedings and against which adequate reserves are being maintained; maintain all of its properties used or useful in its business in good working order and condition, ordinary wear and tear excepted; permit representatives of any Lender or the Administrative Agent, during normal business hours, to examine, copy and make extracts from its books and records, to inspect its properties, and to discuss its business and affairs with its officers, all to the extent reasonably requested by such Lender or the Administrative Agent (as the case may be); and keep insured by financially sound and reputable insurers all property of a character usually insured by corporations engaged in the same or similar business similarly situated against loss or damage of the kinds and in the amounts customarily insured against by such corporations and carry such other insurance as is usually carried by such corporations.

6.4 Use of Proceeds . The Borrower shall use the proceeds of the Loans hereunder for its general corporate purposes (in compliance with all applicable legal and regulatory requirements).

6.5 Environmental Covenant . The Borrower will, and will cause each of its Subsidiaries to:

(a) use and operate all of its facilities and properties in compliance with all Environmental Laws except for such noncompliance which, singly or in the aggregate, will not have a Material Adverse Effect, keep all necessary permits, approvals, certificates, licenses and other authorizations relating to environmental matters in effect and remain in compliance therewith, except where the failure to keep such permits, approvals, certificates, licenses or other authorizations, or any noncompliance with the provisions thereof, will not have a Material Adverse Effect, and handle all Hazardous Materials in compliance with all applicable Environmental Laws, except for any noncompliance that will not have a Material Adverse Effect;

(b) immediately notify the Administrative Agent and provide copies upon receipt of all written inquiries from any Governmental Authority, claims, complaints or notices relating to the condition of its facilities and properties or compliance with Environmental Laws which will have a Material Adverse Effect, and promptly cure and have dismissed with prejudice or investigate and contest in good faith any actions and proceedings relating to material compliance with Environmental Laws; and

(c) provide such information and certifications which the Administrative Agent may reasonably request from time to time to evidence compliance with this Section 6.5 .

6.6 Financial Covenant . The Borrower will not permit the ratio of (i) its Consolidated Financial Indebtedness to (ii) its Consolidated Total Capitalization to exceed 0.65 to 1.0 at any time.

6.7 Local Regulatory Commission Approval . The Borrower shall promptly notify the Administrative Agent in the event that the borrowing of any Loan by the Borrower will require the approval of the Public Service Commission of the District of Columbia, the Public Service Commission of Maryland, or the State Corporation Commission of Virginia. The Borrower will obtain any such required approval prior to the time such approval is required. Promptly upon receipt of any such approval, the Borrower will furnish a copy thereof to the Administrative Agent.

ARTICLE VII

EVENTS OF DEFAULT

The occurrence of any one or more of the following events shall constitute an Event of Default:

7.1 The Borrower fails to pay (i) when and as required to be paid herein, any amount of principal of any Loan or any Reimbursement Obligation, or (ii) within three days after the same becomes due, any interest on any Loan or any fee due hereunder, or (iii) within five days after the same becomes due, any other amount payable hereunder or under any other Loan Document;

7.2 The Borrower or any of its Material Subsidiaries (i) shall default in the payment when due of any principal of or interest on any of its other Indebtedness having an aggregate principal amount of at least $25,000,000, (ii) shall default under any Hedge Agreement covering a notional amount of Indebtedness of at least $25,000,000, (iii) or fails to observe or perform any other agreement or condition relating to any note, agreement, indenture or other document evidencing or relating to any such Indebtedness; or any other event occurs, the effect of which is to cause, or (with the giving of any notice or the lapse of time or both) to permit the holder or holders of such Indebtedness (or a trustee or agent on behalf of such holder or holders) to cause, such Indebtedness to become due prior to its stated maturity.

7.3 Any representation, warranty or certification made or deemed made herein by the Borrower, or any certificate furnished to any Lender or the Administrative Agent pursuant to the provisions hereof, shall prove to have been false or misleading as of the time made, deemed made, or furnished in any material respect.

7.4 The Borrower shall default in the performance of its obligations under Section 6.1(e) or 6.6 hereof.

7.5 The Borrower shall default in the performance of any of its other obligations in this Agreement and such default shall continue unremedied for a period of 15 days after the earlier of (i) the date on which a senior officer of the Borrower becomes aware of such default, or (ii) the date on which notice thereof is given to the Borrower by the Administrative Agent or any Lender (through the Administrative Agent).

7.6 The Borrower or any of its Material Subsidiaries shall admit in writing its inability to, or be generally unable to, pay its debts as such debts become due.

7.7 The Borrower or any of its Material Subsidiaries shall (i) apply for or consent to the appointment of, or the taking of possession by, a receiver, custodian, trustee or liquidator of itself or of all or a substantial part of its property, (ii) make a general assignment for the benefit of its creditors, (iii) commence a voluntary case under the Bankruptcy Code (as now or hereafter in effect), (iv) file a petition seeking to take advantage of any other law relating to bankruptcy, insolvency, reorganization, winding-up, or composition or readjustment of debts, (v) fail to controvert in a timely and appropriate manner, or acquiesce in writing to, any petition filed against it in an involuntary case under the Bankruptcy Code, or (vi) take any corporate action for the purpose of effecting any of the foregoing.

7.8 A proceeding or case shall be commenced, without the application or consent of the Borrower or any of its Material Subsidiaries, in any court of competent jurisdiction, seeking (i) its liquidation, reorganization, dissolution or winding-up, or the composition or readjustment of its debts, (ii) the appointment of a trustee, receiver, custodian, liquidator or the like of the Borrower or such Material Subsidiary or of all or any substantial part of its assets, or (iii) similar relief in respect of the Borrower or such Material Subsidiary under any law relating to bankruptcy, insolvency, reorganization, winding-up or composition or adjustment of debts, and such proceeding or case shall continue undismissed, or an order, judgment or decree approving or ordering any of the foregoing shall be entered and continue unstayed and in effect, for a period of 60 days; or an order for relief against the Borrower or such Material Subsidiary shall be entered in an involuntary case under the Bankruptcy Code.

7.9 A final judgment or judgments for the payment of money in excess of $50,000,000 in the aggregate that is not covered by insurance, performance bonds or the like shall be rendered by a court or courts against the Borrower or any of its Subsidiaries, and the same shall not be discharged (or provision shall not be made for such discharge), or a stay of execution thereof shall not be procured, within 90 days from the date of entry thereof and the Borrower or the relevant Subsidiary shall not, within said period of 90 days, or such longer period during which execution of the same shall have been stayed, appeal therefrom and cause the execution thereof to be stayed during such appeal.

7.10 Any of the following events shall occur with respect to any Pension Plan:

(i) the institution of any steps by the Borrower, any member of its Controlled Group or any other Person to terminate a Pension Plan if, as a result of such termination, the Borrower or any such member could be required to make a contribution to such Pension Plan, or could reasonably expect to incur a liability or obligation to such Pension Plan, in excess of $50,000,000; or

(ii) the complete or partial withdrawal from any Pension Plan by the Borrower or any member of its Controlled Group if, as a result of such withdrawal, the Borrower or any such member could incur any liability by such Pension Plan in excess of $50,000,000; or

(iii) a contribution failure occurs with respect to any Pension Plan sufficient to give rise to a Lien under Section 302(f) of ERISA.

7.11 Any license, consent, authorization or approval, filing or registration now or hereafter necessary to enable the Borrower to comply with its obligations hereunder or under the Notes shall be revoked, withdrawn, withheld or not effected or shall cease to be in full force and effect.

7.12 The occurrence of any Change in Control.

ARTICLE VIII

REMEDIES, WAIVERS AND AMENDMENTS

8.1 Remedies Upon Event of Default . If any Event of Default occurs and is continuing, the Administrative Agent shall, at the request of, or may, with the consent of, the Required Lenders, take any or all of the following actions:

8.1.1 declare the commitment of each Lender to make Loans and any obligation of the Issuing Banks to issue Letters of Credit to be terminated, whereupon such commitments and obligation shall be terminated;

8.1.2 declare the unpaid principal amount of all outstanding Loans, all interest accrued and unpaid thereon, and all other amounts owing or payable hereunder or under any other Loan Document to be immediately due and payable, without presentment, demand, protest or other notice of any kind, all of which are hereby expressly waived by the Borrower;

8.1.3 require that the Borrower Cash Collateralize the aggregate Stated Amount of outstanding Letters of Credit (in an amount equal to 102% of the aggregate Stated Amount thereof); and

8.1.4 exercise on behalf of itself, the Lenders and the Issuing Banks all rights and remedies available to it, the Lenders and the Issuing Banks under the Loan Documents;

provided , however , that upon the occurrence of any Event of Default described in Section 7.6 , 7.7 or 7.8 occurs with respect to the Borrower, the obligation of each Lender to make Loans and any obligation of any Issuing Bank to issue Letters of Credit shall automatically terminate, the unpaid principal amount of all outstanding Loans and all interest and other amounts as aforesaid shall automatically become due and payable, and the obligation of the Borrower to Cash Collateralize the aggregate Stated Amount of Letters of Credit as aforesaid shall automatically become effective, in each case without further act of the Administrative Agent or any Lender.

If, within 30 days after acceleration of the maturity of the Obligations or termination of the obligations of the Lenders to make Loans hereunder as a result of any Event of Default (other than any Event of Default as described in Section 7.6 , 7.7 or 7.8) and before any judgment or decree for the payment of the Obligations due shall have been obtained or entered, the Required Lenders (in their sole discretion) shall so direct, the Administrative Agent shall, by notice to the Borrower, rescind and annul such acceleration and/or termination.

8.2 Amendments . Subject to the provisions of this Article VIII , the Required Lenders (or the Administrative Agent with the consent in writing of the Required Lenders) and the Borrower may enter into agreements supplemental hereto for the purpose of adding or modifying any provisions to the Loan Documents or changing in any manner the rights of the Lenders or the Borrower hereunder or waiving any Event of Default hereunder; provided , however , that no such supplemental agreement shall, without the consent of each Lender affected thereby:

(i) Extend the final maturity of any Loan or forgive all or any portion of the principal amount thereof, or reduce the rate or extend the time of payment of interest or fees thereon;

(ii) Increase any Commitment of any such Lender over the amount thereof in effect or extend the maturity thereof (it being understood that a waiver of any condition precedent set forth in Section 4.2 or of any Unmatured Default or Event of Default or mandatory reduction in the Commitments, if agreed to by the Required Lenders or all Lenders (as may be required hereunder with respect to such waiver), shall not constitute such an increase);

(iii) Reduce the percentage specified in the definition of Required Lenders;

(iv) Extend the Facility Termination Date (except as set forth in Section 2.6), increase the period by which the Repayment Date may be extended, reduce the amount or extend the payment date for, the mandatory payments required under Section 2.1.2 , increase the amount the Commitment of such Lender hereunder (without the consent of such Lender), or permit the Borrower to assign its rights under this Agreement;

(v) Alter any provision in this Agreement providing for the pro rata treatment of the Lenders;

(vi) Amend this Section 8.2 or any provision of this Agreement requiring the consent or other action of all of the Lenders; or

(vii) Unless agreed to in writing by the Issuing Banks, the Swingline Lender or the Administrative Agent in addition to the Lenders required as provided hereinabove to take such action, affect the respective rights or obligations of the Issuing Bank, the Swingline Lender or the Administrative Agent, as applicable, hereunder or under any of the other Loan Documents.

Notwithstanding the fact that the consent of all Lenders is required in certain circumstances as set forth above, each Lender is entitled to vote as such Lender sees fit on any bankruptcy reorganization plan that affects the Loans, and each Lender acknowledges that the provisions of Section 1126(c) of the Bankruptcy Code supersedes the unanimous consent provisions set forth herein.

Notwithstanding anything to the contrary herein, (i) no Defaulting Lender shall have any right to approve or disapprove any amendment, waiver or consent hereunder (and any amendment, waiver or consent which by its terms requires the consent of all Lenders or each affected Lender may be effected with the consent of the applicable Lenders other than Defaulting Lenders), except that (x) the Commitment of any Defaulting Lender may not be increased or extended without the consent of such Lender and (y) any waiver, amendment or modification requiring the consent of all Lenders or each affected Lender that by its terms affects any Defaulting Lender more adversely than other affected Lenders shall require the consent of such Defaulting Lender and (ii) if the Administrative Agent and the Borrower shall have jointly identified (each in its sole discretion) an obvious error or omission of a technical or immaterial nature, in each case, in any provision of the Loan Documents, then the Administrative Agent and the Borrower shall be permitted to amend such provision and such amendment shall become effective without any further action or consent of any other party to any Loan Document if the same is not objected to in writing by the Required Lenders within five Business Days following the posting of such amendment to the Lenders.

No amendment of any provision of this Agreement relating to the Administrative Agent shall be effective without the written consent of the Administrative Agent. The Administrative Agent may waive payment of the fee required under Section 12.3.2 without obtaining the consent of any other party to this Agreement.

8.3 Preservation of Rights . No delay or omission of the Lenders or the Administrative Agent to exercise any right under the Loan Documents shall impair such right or be construed to be a waiver of any Event of Default or an acquiescence therein, and the making of a Loan notwithstanding the existence of an Event of Default or the inability of the Borrower to satisfy the conditions precedent to such Loan shall not constitute any waiver or acquiescence. Any single or partial exercise of any such right shall not preclude other or further exercise thereof or the exercise of any other right, and no waiver, amendment or other variation of the terms, conditions or provisions of the Loan Documents whatsoever shall be valid unless in writing signed by the Lenders required pursuant to Section 8.2 , and then only to the extent in such writing specifically set forth. All remedies contained in the Loan Documents or by law afforded shall be cumulative and all shall be available to the Administrative Agent and the Lenders until the Obligations have been paid in full.

ARTICLE IX

GENERAL PROVISIONS

9.1 Survival of Representations . All representations and warranties of the Borrower contained in this Agreement shall survive during the period that the Loans herein contemplated are outstanding.

9.2 Governmental Regulation . Anything contained in this Agreement to the contrary notwithstanding, no Lender shall be obligated to extend credit to the Borrower in violation of any limitation or prohibition provided by any Applicable Law.

9.3 Headings . Headings to Articles, Sections and subsections of, and Annexes, Schedules and Exhibits to the Loan Documents are for convenience of reference only, and shall not govern the interpretation of any of the provisions of the Loan Documents.

9.4 Entire Agreement . The Loan Documents embody the entire agreement and understanding among the Borrower, the Administrative Agent and the Lenders and supersede all prior agreements and understandings among the Borrower, the Administrative Agent and the Lenders relating to the subject matter thereof.

9.5 Several Obligations; Benefits of this Agreement . The respective obligations of the Lenders hereunder are several and not joint and no Lender shall be the partner or agent of any other (except to the extent to which the Administrative Agent is authorized to act as such). The failure of any Lender to perform any of its obligations hereunder shall not relieve any other Lender from any of its obligations hereunder. This Agreement shall not be construed so as to confer any right or benefit upon any Person other than the parties to this Agreement and their respective successors and assigns; provided, however, that the parties hereto expressly agree that the Arrangers shall enjoy the benefits of the provisions of Sections 9.6, 9.10 and 9.11 to the extent specifically set forth therein and shall have the right to enforce such provisions on its own behalf and in its own name to the same extent as if it were a party to this Agreement.

9.6 Expenses; Indemnification.

9.6.1 Expenses. The Borrower shall pay:

(i) the Administrative Agent and the Arrangers for any reasonable costs, internal charges and out of pocket expenses (including attorneys' fees and time charges of attorneys for the Administrative Agent, which attorneys may be employees of the Administrative Agent) paid or incurred by the Administrative Agent or the Arrangers, and their respective Affiliates, in connection with the preparation, negotiation, execution, delivery, syndication, review, amendment, modification, and administration of the Loan Documents;

(ii) the Administrative Agent, the Arrangers, the Issuing Banks and the Lenders for any reasonable costs, internal charges and out of pocket expenses (including attorneys' fees and time charges of attorneys for the Administrative Agent, the Arrangers, the Issuing Banks and the Lenders, which attorneys may be employees of the Administrative Agent, the Arrangers, the Issuing Banks or the Lenders) paid or incurred by the Administrative Agent, the Arrangers, the Issuing Banks or any Lender in connection with the collection and enforcement of its rights (A) in connection with this Agreement and the other Loan Documents, including its rights under this Section 9.6, or (B) in connection with the Loans made or Letters of Credit issued hereunder, including all such out of pocket expenses incurred during any workout, restructuring or negotiations in respect of such Loans or Letters of Credit;

(iii) the Issuing Banks in connection with the issuance of any Letter of Credit or demand for payment thereunder; and

(iv) any civil penalty or fine assessed by OFAC against, and all reasonable costs and expenses (including counsel fees and disbursements) incurred in connection with defense thereof by, the Administrative Agent, any Issuing Bank or any Lender as a result of conduct of the Borrower that violates a sanction enforced by OFAC.

9.6.2 Indemnification by the Borrower. The Borrower shall indemnify the Administrative Agent (and any sub-agent thereof), each Lender, each Issuing Bank and each Related Party of any of the foregoing persons (each such person being called an "Indemnitee") against, and hold each Indemnitee harmless from, any and all losses, claims, damages, liabilities and related expenses (including the fees, charges and disbursements of any counsel for any Indemnitee), incurred by any Indemnitee or asserted against any Indemnitee by any Person (including the Borrower and any of its Subsidiaries) other than such Indemnitee and its Related Parties arising out of, in connection with, or as a result of (i) the execution or delivery of this Agreement, any other Loan Document or any agreement or instrument contemplated hereby or thereby, the performance by the parties hereto of their respective obligations hereunder or thereunder or the consummation of the transactions contemplated hereby or thereby, (ii) any Loan or Letter of Credit or the use or proposed use of the proceeds therefrom (including any refusal by the Issuing Bank to honor a demand for payment under a Letter of Credit if the documents presented in connection with such demand do not strictly comply with the terms of such Letter of Credit), (iii) any actual or alleged presence or release of Hazardous Material on or from any property owned or operated by the Borrower of any of its Subsidiaries, or any environmental claim related in any way the Borrower or its Subsidiaries, or (iv) any actual or prospective claim, litigation, investigation or proceeding relating to any of the foregoing, whether based on contract, tort or any other theory, whether brought by a third party or by the Borrower or its Subsidiaries, and regardless of whether any Indemnitee is a party thereto; provided that such indemnity shall not, as to any Indemnitee, be available to the extent that such losses, claims, damages, liabilities or related expenses (x) are determined by a court of competent jurisdiction by final and nonappealable judgment to have resulted from the gross negligence or willful misconduct of such Indemnitee or (y) result from a claim brought by the Borrower or any of its Subsidiaries against an Indemnitee for breach in bad faith of such Indemnitee's obligations hereunder or under any other Loan Document, if the Borrower or such Credit Party has obtained a final and nonappealable judgment in its favor on such claim as determined by a court of competent jurisdiction. This Section 9.6.2 shall not apply with respect to Taxes other than any Taxes that represent losses, claims, damages or related liabilities or expenses arising from any non-Tax claim.

9.6.3 Payments on Demand . All amounts due under this Section 9.6 shall be payable by the Borrower upon demand therefor.

9.7 Numbers of Documents . All statements, notices, closing documents, and requests hereunder shall be furnished to the Administrative Agent with sufficient counterparts so that the Administrative Agent may furnish one to each of the Lenders.

9.8 Accounting . Except as provided to the contrary herein, all accounting terms used herein shall be interpreted and all accounting determinations hereunder shall be made in accordance with GAAP, except that any calculation or determination which is to be made on a consolidated basis shall be made for the Borrower and all its Subsidiaries, including those Subsidiaries, if any, which are unconsolidated on the Borrower's audited financial statements.

9.9 Severability of Provisions . Any provision in any Loan Document that is held to be inoperative, unenforceable, or invalid in any jurisdiction shall, as to that jurisdiction, be inoperative, unenforceable or invalid without affecting the remaining provisions in that jurisdiction or the operation, enforceability or validity of that provision in any other jurisdiction, and to this end the provisions of all Loan Documents are declared to be severable. To the extent permitted by Applicable Law, the Borrower hereby waives any provision of Applicable Law that renders any provision of the Loan Documents prohibited or unenforceable in any respect.

9.10 Nonliability of Lenders . The relationship between the Borrower on the one hand and the Lenders and the Administrative Agent on the other hand shall be solely that of borrower and lender. Neither the Administrative Agent, the Arrangers, nor any Lender shall have any fiduciary responsibilities to the Borrower. Neither the Administrative Agent, the Arrangers, nor any Lender undertakes any responsibility to the Borrower to review or inform the Borrower of any matter in connection with any phase of the Borrower's business or operations. The Borrower agrees that neither the Administrative Agent, the Arrangers nor any Lender shall have liability to the Borrower (whether sounding in tort, contract or otherwise) for losses suffered by the Borrower in connection with, arising out of, or in any way related to, the transactions contemplated and the relationship established by the Loan Documents, or any act, omission or event occurring in connection therewith, unless it is determined in a final non-appealable judgment by a court of competent jurisdiction that such losses resulted from the gross negligence or willful misconduct of the party from which recovery is sought. Neither the Administrative Agent, the Arrangers nor any Lender shall have any liability with respect to, and the Borrower hereby waives, releases and agrees not to sue for, any special, indirect, punitive or consequential damages suffered by the Borrower in connection with, arising out of, or in any way related to the Loan Documents or the transactions contemplated thereby.

9.11 Confidentiality . Each Lender agrees to hold any confidential information which it may receive from the Borrower pursuant to this Agreement in confidence, except for disclosure (i) to its Affiliates and to other Lenders and their respective Affiliates, (ii) to legal counsel, accountants, and other professional advisors to such Lender or to a Transferee, (iii) to regulatory officials, (iv) to any Person as requested pursuant to or as required by Applicable Law, (v) to any Person in connection with any legal proceeding to which such Lender is a party, (vi) to such Lender's direct or indirect contractual counterparties in swap agreements or to legal counsel, accountants and other professional advisors to such counterparties, and (vii) permitted by Section 12.4 .

9.12 Disclosure . The Borrower and each Lender hereby acknowledge and agree that the Administrative Agent and/or its Affiliates from time to time may hold investments in, make other loans to or have other relationships with the Borrower and its Affiliates.

9.13 Rights Cumulative . Each of the rights and remedies of the Administrative Agent and the Lenders under the Loan Documents shall be in addition to all of their other rights and remedies under the Loan Documents and Applicable Law, and nothing in the Loan Documents shall be construed as limiting any such rights or remedies.

9.14 Syndication Agent; Documentation Agents . Neither the Syndication Agent nor the Documentation Agents shall have any liability or obligation whatsoever to the Borrower, the Administrative Agent or any Lender at any time under this Agreement, other than its obligations as a Lender hereunder.

ARTICLE X

THE ADMINISTRATIVE AGENT

10.1 Appointment and Authority . Each of the Lenders (for purposes of this ARTICLE X , references to the Lenders shall also mean the Issuing Bank and the Swingline Lender) hereby irrevocably appoints Wells Fargo to act on its behalf as the Administrative Agent hereunder and under the other Loan Documents and authorizes the Administrative Agent to take such actions on its behalf and to exercise such powers as are delegated to the Administrative Agent by the terms hereof or thereof, together with such actions and powers as are reasonably incidental thereto. Except as set forth in Section 10.6 , the provisions of this ARTICLE X are solely for the benefit of the Administrative Agent and the Lenders, and neither the Borrower nor of its Subsidiaries shall have rights as a third-party beneficiary of any of such provisions. It is understood and agreed that the use of the term "agent" (or any other similar term) herein or in any other Loan Document with reference to the Administrative Agent is not intended to connote any fiduciary or other implied (or express) obligations under agency doctrine of any Applicable Law. Instead, such term is used as a matter of market custom, and is intended to create or reflect only an administrative relationship between contracting parties.

10.2 Rights as a Lender . The Person serving as the Administrative Agent hereunder shall have the same rights and powers in its capacity as a Lender as any other Lender and may exercise the same as though it were not the Administrative Agent, and the term " Lender " or " Lenders " shall, unless otherwise expressly indicated or unless the context otherwise requires, include the Person serving as the Administrative Agent hereunder in its individual capacity. Such Person and its Affiliates may accept deposits from, lend money to, own securities of, act as the financial advisor or in any other advisory capacity for and generally engage in any kind of business with the Borrower or any Subsidiary or other Affiliate thereof as if such Person were not the Administrative Agent hereunder and without any duty to account therefor to the Lenders.

10.3 Exculpatory Provisions .

10.3.1 The Administrative Agent shall not have any duties or obligations except those expressly set forth herein and in the other Loan Documents, and its duties hereunder shall be administrative in nature. Without limiting the generality of the foregoing, the Administrative Agent:

(i) shall not be subject to any fiduciary or other implied duties, regardless of whether an Unmatured Default or Event of Default has occurred and is continuing;

(ii) shall not have any duty to take any discretionary action or exercise any discretionary powers, except discretionary rights and powers expressly contemplated hereby or by the other Loan Documents that the Administrative Agent is required to exercise as directed in writing by the Required Lenders (or such other number or percentage of the Lenders as shall be expressly provided for herein or in the other Loan Documents); provided that the Administrative Agent shall not be required to take any action that, in its opinion or the opinion of its counsel, may expose the Administrative Agent to liability or that is contrary to any Loan Document or Applicable Law, including, for the avoidance of doubt, any action that may be in violation of the automatic stay under any the Bankruptcy Code or under other applicable bankruptcy, insolvency or similar law now or hereafter in effect or that may effect a forfeiture, modification or termination of property of a Defaulting Lender in violation of the Bankruptcy Code or any other applicable bankruptcy insolvency or similar law now or hereafter in effect; and

(iii) shall not, except as expressly set forth herein and in the other Loan Documents, have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Borrower or any of its Affiliates that is communicated to or obtained by the Person serving as the Administrative Agent or any of its Affiliates in any capacity.

10.3.2 The Administrative Agent shall not be liable for any action taken or not taken by it (i) with the consent or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as the Administrative Agent shall believe in good faith shall be necessary, under the circumstances as provided in Sections 8.2 and 8.1), or (ii) in the absence of its own gross negligence or willful misconduct as determined by a court of competent jurisdiction by final and nonappealable judgment. The Administrative Agent shall be deemed not to have knowledge of any Unmatured Default or Event of Default unless and until notice describing such Unmatured Default or Event of Default is given to the Administrative Agent in writing by the Borrower or a Lender.

10.3.3 The Administrative Agent shall not be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with this Agreement or any other Loan Document, (ii) the contents of any certificate, report or other document delivered hereunder or thereunder or in connection herewith or therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth herein or therein or the occurrence of any Unmatured Default or Event of Default, (iv) the validity, enforceability, effectiveness or genuineness of this Agreement, any other Loan Document or any other agreement, instrument or document or (v) the satisfaction of any condition set forth in ARTICLE IV or elsewhere herein, other than to confirm receipt of items expressly required to be delivered to the Administrative Agent.

10.4 Reliance by Administrative Agent . The Administrative Agent shall be entitled to rely upon, and shall not incur any liability for relying upon, any notice, request, certificate, consent, statement, instrument, document or other writing (including any electronic message, internet or intranet website posting or other distribution) believed by it to be genuine and to have been signed, sent or otherwise authenticated by the proper Person. The Administrative Agent also may rely upon any statement made to it orally or by telephone and believed by it to have been made by the proper Person, and shall not incur any liability for relying thereon. In determining compliance with any condition hereunder to the making of a Loan, or the issuance, extension, renewal or increase of a Letter of Credit, that by its terms must be fulfilled to the satisfaction of a Lender or the Issuing Bank, the Administrative Agent may presume that such condition is satisfactory to such Lender or the Issuing Bank unless the Administrative Agent shall have received notice to the contrary from such Lender or the Issuing Bank prior to the making of such Loan or the issuance, extension, renewal or increase of such Letter of Credit. The Administrative Agent may consult with legal counsel (who may be counsel for the Borrower), independent accountants and other experts selected by it, and shall not be liable for any action taken or not taken by it in accordance with the advice of any such counsel, accountants or experts.

10.5 Delegation of Duties . The Administrative Agent may perform any and all of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub-agents appointed by the Administrative Agent. The Administrative Agent and any such sub-agent may perform any and all of its duties and exercise its rights and powers by or through their respective Related Parties. The exculpatory provisions of this Article shall apply to any such sub-agent and to the Related Parties of the Administrative Agent and any such sub-agent, and shall apply to their respective activities in connection with the syndication of the credit facilities provided for herein as well as activities as Administrative Agent. The Administrative Agent shall not be responsible for the negligence or misconduct of any sub-agent except to the extent that a court of competent jurisdiction determines in a final and nonappealable judgment that the Administrative Agent acted with gross negligence or willful misconduct in the selection of such sub-agent.

10.6 Resignation of Administrative Agent .

10.6.1 Resignation Effective Date . The Administrative Agent may at any time give notice of its resignation to the Lenders and the Borrower. Upon receipt of any such notice of resignation, the Required Lenders shall have the right, in consultation with the Borrower, to appoint a successor, which shall be a bank with an office in the United States, or an Affiliate of any such bank with an office in the United States. If no such successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 30 days after the retiring Administrative Agent gives notice of its resignation (or such earlier day as shall be agreed by the Required Lenders) (the " Resignation Effective Date "), then the retiring Administrative Agent may (but shall not be obligated to), on behalf of the Lenders, appoint a successor Administrative Agent meeting the qualifications set forth above. Regardless of whether a successor has been appointed or has accepted such appointment, such resignation shall become effective in accordance with such note on the Resignation Effective Date.

10.6.2 Discharge of Duties After Resignation . With effect from the Resignation Effective Date, (i) the retiring Administrative Agent shall be discharged from its duties and obligations hereunder and under the other Loan Documents (except that in the case of any collateral security held by the Administrative Agent on behalf of the Lenders under any of the Loan Documents, the retiring Administrative Agent shall continue to hold such collateral security until such time as a successor Administrative Agent is appointed) and (ii) except for any indemnity payments owed to the retiring Administrative Agent, all payments, communications and determinations provided to be made by, to or through the Administrative Agent shall instead be made by or to each Lender directly, until such time, if any, as the Required Lenders appoint a successor Administrative Agent as provided for in Section 10.6.1 . Upon the acceptance of a successor's appointment as Administrative Agent hereunder, such successor shall succeed to and become vested with all of the rights, powers, privileges and duties of the retiring Administrative Agent (other than any rights to indemnity payments owed to the retiring Administrative Agent), and the retiring Administrative Agent shall be discharged from all of its duties and obligations hereunder or under the other Loan Documents. The fees payable by the Borrower to a successor Administrative Agent shall be the same as those payable to its predecessor unless otherwise agreed between the Borrower and such successor. After the retiring Administrative Agent's resignation hereunder and under the other Loan Documents, the provisions of this ARTICLE X and Section 9.6 shall continue in effect for the benefit of such retiring Administrative Agent, its sub-agents and their respective Related Parties in respect of any actions taken or omitted to be taken by any of them while the retiring Administrative Agent was acting as Administrative Agent.

10.7 Non-Reliance on Administrative Agent and Other Lenders . Each Lender acknowledges that it has, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement. Each Lender also acknowledges that it will, independently and without reliance upon the Administrative Agent or any other Lender or any of their Related Parties and based on such documents and information as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder.

10.8 No Other Duties, etc . Anything herein to the contrary notwithstanding, none of the Arrangers, Syndication Agent, Documentation Agents or other agents listed on the cover page hereof shall have any powers, duties or responsibilities under this Agreement or any of the other Loan Documents, except in its capacity, as applicable, as the Administrative Agent or a Lender hereunder.

10.9 Administrative Agent May File Proofs of Claim . In case of the pendency of any proceeding under the Bankruptcy Code or under other applicable bankruptcy, insolvency or similar law now or hereafter in effect or any other judicial proceeding relative to the Borrower or any of its Subsidiaries, the Administrative Agent (irrespective of whether the principal of any Loan or Reimbursement Obligation shall then be due and payable as herein expressed or by declaration or otherwise and irrespective of whether the Administrative Agent shall have made any demand on the Borrower) shall be entitled and empowered (but not obligated) by intervention in such proceeding or otherwise (i) to file and prove a claim for the whole amount of the principal and interest owing and unpaid in respect of the Loans, Reimbursement Obligations and all other Obligations that are owing and unpaid and to file such other documents as may be necessary advisable in order to have the claims of the Lenders and the Administrative Agent (including any claim for the reasonable compensation, expenses, disbursements and advances of the Lenders and the Administrative Agent and their respective agents, sub-agents and counsel and all other amounts due the Lenders and the Administrative Agent under Sections 2.4 and 9.6) allowed in such judicial proceeding and (ii) to collect and receive any monies or other property payable or deliverable on any such claims and to distribute the same. Any custodian, receiver, assignee, trustee, liquidator, sequestrator or other similar official in any such judicial proceeding is hereby authorized by each Lender to make such payments to the Administrative Agent and, in the event that the Administrative Agent shall consent to the making of such payments to the Lenders, to pay to the Administrative Agent any amount due for the reasonable compensation, expenses, disbursements and advances of the Administrative Agent and its agents, sub-agents and counsel, and any other amounts due the Administrative Agent under Section 2.4 or 9.6 .

10.10 Issuing Bank and Swingline Lender . The provisions of this ARTICLE X (other than Section 10.2) shall apply to the Issuing Bank and the Swingline Lender mutatis mutandis to the same extent as such provisions apply to the Administrative Agent.

ARTICLE XI

SETOFF; RATABLE PAYMENTS

11.1 Setoff . In addition to, and without limitation of, any rights of the Lenders under Applicable Law, if the Borrower becomes insolvent, however evidenced, or any Event of Default occurs, each Lender, the Issuing Banks and each of their respective Affiliates is hereby authorized at any time and from time to time, to the fullest extent permitted by Applicable Law, to set off and apply any and all deposits (general or special, time or demand, provisional or final, in whatever currency) at any time held, and other obligations (in whatever currency) at any time owing, by such Lender, such Issuing Bank or any such Affiliate, to or for the credit or the account of the Borrower against any and all of the obligations of the Borrower now or hereafter existing under this Agreement or any other Loan Document to such Lender or such Issuing Bank or their respective Affiliates, irrespective of whether or not such Lender, such Issuing Bank or such Affiliate shall have made any demand under this Agreement or any other Loan Document and although such obligations of the Borrower may be contingent or unmatured or are owed to a branch, office or Affiliate of such Lender or such Issuing Bank different from the branch, office or Affiliate holding such deposit or obligated on such indebtedness; provided that in the event that any Defaulting Lender shall exercise any such right of setoff, (i) all amounts so set off shall be paid over immediately to the Administrative Agent for further application in accordance with the provisions of Section 2.18 and, pending such payment, shall be segregated by such Defaulting Lender from its other funds and deemed held in trust for the benefit of the Administrative Agent, the Issuing Banks and the Lenders (including the Swingline Lender), and (ii) the Defaulting Lender shall provide promptly to the Administrative Agent a statement describing in reasonable detail the obligations owing to such Defaulting Lender as to which it exercised such right of setoff. The rights of each Lender, each Issuing Bank and their respective Affiliates under this Section 11.1 are in addition to other rights and remedies (including other rights of setoff) that such Lender, such Issuing Bank or their respective Affiliates may have. Each Lender and each Issuing Bank agrees to notify the Borrower and the Administrative Agent promptly after any such setoff and application; provided that the failure to give such notice shall not affect the validity of such setoff and application.

11.2 Ratable Payments . If any Lender, whether by setoff or otherwise, has payment made to it upon Obligations owing to it in a greater proportion than that received by any other Lender, such Lender agrees, promptly upon demand, to (i) notify the Administrative Agent of such fact and (ii) purchase participations (for cash at face value) in the Obligations held by the other Lenders so that after such acquisition each Lender will hold its ratable proportion of the then outstanding Obligations; provided that (i) if any such participations are purchased and all or any portion of the payment giving rise thereto is recovered, such participations shall be rescinded and the purchase price restored to the extent of such recovery, without interest, and (ii) the provisions of this Section 11.2 shall not be construed to apply to (x) any payment made by the Borrower pursuant to and in accordance with the express terms of this Agreement (including the application of funds arising from the existence of a Defaulting Lender) or (y) any payment obtained by a Lender as consideration for the assignment of or sale of a participation in any of its Loans or participations in Reimbursement Obligations or Swingline Loans to any assignee or Participant, other than to the Borrower or any Subsidiary thereof (as to which the provisions of this Section 11.2 shall apply). The Borrower consents to the foregoing and agrees, to the extent it may effectively do so under Applicable Law, that any Lender acquiring a participation pursuant to the foregoing arrangements may exercise against the Borrower rights of setoff and counterclaim with respect to such participation as fully as if such Lender were a direct creditor of the Borrower in the amount of such participation. If under the Bankruptcy Code or under other applicable bankruptcy, insolvency or similar law now or hereafter in effect, any Lender receives a secured claim in lieu of a setoff to which this Section 11.2 applies, such Lender shall, to the extent practicable, exercise its rights in respect of such secured claim in a manner consistent with the rights of the Lenders entitled under this Section 11.2 to share in the benefits of any recovery on such secured claim. If any Lender, whether in connection with setoff or amounts which might be subject to setoff or otherwise, receives collateral or other protection for its Obligations or other amounts which may be subject to setoff, such Lender agrees, promptly upon demand, to take such action necessary such that all Lenders share in the benefits of such collateral or other protection ratably in proportion to their Loans. In case any such payment is disturbed by legal process, or otherwise, appropriate further adjustments shall be made.

ARTICLE XII

BENEFIT OF AGREEMENT; ASSIGNMENTS; PARTICIPATIONS

12.1 Successors and Assigns . The terms and provisions of the Loan Documents shall be binding upon and inure to the benefit of the Borrower and the Lenders and their respective successors and assigns, except that (i) the Borrower shall not have the right to assign its rights or obligations under the Loan Documents and (ii) any assignment by any Lender must be made in compliance with Section 12.3 . The parties to this Agreement acknowledge that clause (ii) of this Section 12.1 relates only to absolute assignments and does not prohibit assignments creating security interests, including, without limitation, any pledge or assignment by any Lender of all or any portion of its rights under this Agreement and any Note to a Federal Reserve Bank; provided , however , that no such pledge or assignment creating a security interest shall release the transferor Lender from its obligations hereunder unless and until the parties thereto have complied with the provisions of Section 12.3 . The Administrative Agent may treat the Person which made any Loan or which holds any Note as the owner thereof for all purposes hereof unless and until such Person complies with Section 12.3 ; provided , however , that the Administrative Agent may in its discretion (but shall not be required to) follow instructions from the Person which made any Loan or which holds any Note to direct payments relating to such Loan or Note to another Person. Any assignee of the rights to any Loan or any Note agrees by acceptance of such assignment to be bound by all the terms and provisions of the Loan Documents. Any request, authority or consent of any Person, who at the time of making such request or giving such authority or consent is the owner of the rights to any Loan (whether or not a Note has been issued in evidence thereof), shall be conclusive and binding on any subsequent holder or assignee of the rights to such Loan.

12.2 Participations .

12.2.1 Permitted Participants; Effect . Any Lender may, in the ordinary course of its business and in accordance with Applicable Law, at any time sell to one or more banks or other entities (" Participants ") participating interests in any Loan owing to such Lender, any Note held by such Lender, any Commitment of such Lender or any other interest of such Lender under the Loan Documents. In the event of any such sale by a Lender of participating interests to a Participant, such Lender's obligations under the Loan Documents shall remain unchanged, such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations, such Lender shall remain the owner of its Loans and the holder of any Note issued to it in evidence thereof for all purposes under the Loan Documents, all amounts payable by the Borrower under this Agreement shall be determined as if such Lender had not sold such participating interests, and the Borrower and the Administrative Agent shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under the Loan Documents. Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to enforce this Agreement and to approve any amendment, modification or waiver of any provision of this Agreement; provided that such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, waiver or other modification described in Section 8.2 that affects such Participant. The Borrower agrees that each Participant shall be entitled to the benefits of Sections 2.18.1 , 2.18.2 , 2.19 , and 2.20 to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to Section 12.3 ; provided that such Participant (A) agrees to be subject to the provisions of Section 2.21 as if it were an assignee under Section 12.3 and (B) shall not be entitled to receive any greater payment under Section 2.18 or 2.19 , with respect to any participation, than its participating Lender would have been entitled to receive, except to the extent such entitlement to receive a greater payment results from a Change in Law that occurs after the Participant acquired the applicable participation. Each Lender that sells a participation agrees, at the Borrower's request and expense, to use reasonable efforts to cooperate with the Borrower to effectuate the provisions of Section 2.21 with respect to any Participant. To the extent permitted by law, each Participant also shall be entitled to the benefits of Section 11.1 as though it were a Lender; provided that such Participant agrees to be subject to Section 11.2 as though it were a Lender. Each Lender that sells a participation shall, acting solely for this purpose as an agent of the Borrower, maintain a register on which it enters the name and address of each Participant and the principal amounts (and stated interest) of each Participant's interest in the Loans or other Obligations under the Loan Documents (the " Participant Register "); provided that no Lender shall have any obligation to disclose all or any portion of the Participant Register (including the identity of any Participant or any information relating to a Participant's interest in any Commitments, Loans, Letters of Credit or its other obligations under any Loan Document) to any Person except to the extent that such disclosure is necessary to establish such Commitment, Loan, Letter of Credit or other obligation is in registered form under Section 5f.103-1(c) of the United States Treasury Regulations. The entries in the Participant Register shall be conclusive absent manifest error, and such Lender shall treat each Person whose name is recorded in the Participant Register as the owner of such participation for all purposes of this Agreement. For the avoidance of doubt, the Administrative Agent (in its capacity as Administrative Agent) shall have no responsibility for maintaining a Participant Register.

12.2.2 Certain Pledges . Any Lender may at any time pledge or assign a security interest in all or any portion of its rights under this Agreement (including under its Notes, if any) to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank; provided that no such pledge or assignment shall release such Lender from any of its obligations hereunder or substitute any such pledgee or assignee for such Lender as a party hereto.

12.3 Assignments .

12.3.1 Permitted Assignments . Any Lender may, in the ordinary course of its business and in accordance with Applicable Law, at any time assign to one or more banks or other entities (" Purchasers ") all or any part of its rights and obligations under the Loan Documents. Such assignment shall be pursuant to an agreement substantially in the form of Exhibit 12.3.1 . The consent of the Borrower and the Administrative Agent shall be required prior to an assignment becoming effective with respect to a Purchaser which is not a Lender or an Affiliate thereof; provided , however , that if an Event of Default has occurred and is continuing, the consent of the Borrower shall not be required; provided further that the Borrower shall be deemed to have consented to any such assignment unless it shall object thereto by written notice to the Administrative Agent within five Business Days after having received notice thereof. Such consent shall not be unreasonably withheld or delayed. Each such assignment with respect to a Purchaser which is not a Lender or an Affiliate thereof shall (unless each of the Borrower and the Administrative Agent otherwise consents) be in an amount not less than the lesser of (i) $5,000,000 or (ii) the remaining amount of the assigning Lender's Commitment (calculated as at the date of such assignment) or outstanding Loans (if the applicable Commitment has been terminated). The consent of the Issuing Banks (such consent not to be unreasonably withheld or delayed) shall be required for any assignment that increases the obligation of the assignee to participate in exposure under one or more Letters of Credit (whether or not then outstanding). The consent of the Swingline Lender (such consent not to be unreasonably withheld or delayed) shall be required for any assignment hereunder. No such assignment shall be made to (A) a natural person, (B) the Borrower or any of its respective Affiliates or Subsidiaries or (C) to any Defaulting Lender or any of its Subsidiaries, or any Person who, upon becoming a Lender hereunder, would constitute any of the foregoing Persons described in this clause.

12.3.2 Effect; Effective Date . Upon (i) delivery to the Administrative Agent of an assignment, together with any consents required by Section 12.3.1 , and (ii) payment of a $3,500 fee to the Administrative Agent for processing such assignment (unless such fee is waived by the Administrative Agent), such assignment shall become effective on the effective date specified in such assignment. On and after the effective date of such assignment, such Purchaser shall for all purposes be a Lender party to this Agreement and any other Loan Document executed by or on behalf of the Lenders and shall have all the rights and obligations of a Lender under the Loan Documents, to the same extent as if it were an original party hereto, and no further consent or action by the Borrower, the Lenders or the Administrative Agent shall be required to release the transferor Lender with respect to the percentage of the Aggregate Commitments assigned to such Purchaser but such transferor Lender shall continue to be entitled to the benefits of Sections 2.18.1 , 2.18.2 , 2.19 , and 2.20 with respect to facts and circumstances occurring prior to the effective date of such assignment; provided that, except to the extent otherwise expressly agreed by the affected parties, no assignment by a Defaulting Lender will constitute a waiver or release of any claim of any party hereunder arising from such Lender's having been a Defaulting Lender. Upon the consummation of any assignment to a Purchaser pursuant to this Section 12.3.2 , the transferor Lender, the Administrative Agent and the Borrower shall, if the transferor Lender or the Purchaser desires that its Loans be evidenced by Notes, make appropriate arrangements so that new Notes or, as appropriate, replacement Notes are issued to such transferor Lender and new Notes or, as appropriate, replacement Notes, are issued to such Purchaser, in each case in principal amounts reflecting their respective Commitments, as adjusted pursuant to such assignment. Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this paragraph shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with Section 12.2.2 .

12.3.3 Assignments by a Defaulting Lender . In connection with any assignment of rights and obligations of any Defaulting Lender hereunder, no such assignment shall be effective unless and until, in addition to the other conditions thereto set forth herein, the parties to the assignment shall make such additional payments to the Administrative Agent in an aggregate amount sufficient, upon distribution thereof as appropriate (which may be outright payment, purchases by the assignee of participations or subparticipations, or other compensating actions, including funding, with the consent of the Borrower and the Administrative Agent, the Applicable Percentage of Loans previously requested but not funded by the Defaulting Lender, to each of which the applicable assignee and assignor hereby irrevocably consent), to (i) pay and satisfy in full all payment liabilities then owed by such Defaulting Lender to the Administrative Agent or any Lender hereunder (and interest accrued thereon), and (ii) acquire (and fund as appropriate) its full share of all Loans and participations in Letters of Credit and Swingline Loans in accordance with its Applicable Percentage. Notwithstanding the foregoing, in the event that any assignment of rights and obligations of any Defaulting Lender hereunder shall become effective under Applicable Law without compliance with the provisions of this paragraph, then the assignee of such interest shall be deemed to be a Defaulting Lender for all purposes of this Agreement until such compliance occurs.

12.3.4 Register . The Administrative Agent, acting solely for this purpose as an agent of the Borrower, shall maintain at its address for notices referred to in Schedule 1.1-B a copy of each Assignment and Assumption delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitments of, and principal amounts (and stated interest) of the Loans owing to, each Lender pursuant to the terms hereof from time to time (the " Register "). The entries in the Register shall be conclusive absent manifest error, and the Borrower, the Administrative Agent and the Lenders shall treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement. In addition, the Administrative Agent shall maintain on the Register information regarding the designation, revocation of designation, of any Lender as a Defaulting Lender. The Register shall be available for inspection by each of the Borrower and the Issuing Bank, at any reasonable time and from time to time upon reasonable prior notice.

12.4 Dissemination of Information . The Borrower authorizes each Lender to disclose to any Participant or Purchaser or any other Person acquiring an interest in the Loan Documents by operation of law (each a " Transferee ") and any prospective Transferee any and all information in such Lender's possession concerning the creditworthiness of the Borrower and its Subsidiaries; provided that each Transferee and prospective Transferee agrees to be bound by Section 9.11 of this Agreement.

12.5 Tax Treatment . If any interest in any Loan Document is transferred to any Transferee which is organized under the laws of any jurisdiction other than the United States or any State thereof, the transferor Lender shall cause such Transferee, concurrently with the effectiveness of such transfer, to comply with the provisions of Section 2.19 .

ARTICLE XIII

NOTICES

13.1 Notices . Except as otherwise permitted by Section 2.12 with respect to Borrowing Notices, Swingline Borrowing Notices and Continuation/Conversion Notices, all notices, requests and other communications to any party hereunder shall be in writing (including electronic transmission, facsimile transmission or similar writing) and shall be given to such party: (i) in the case of the Borrower or the Administrative Agent, at its address or facsimile number set forth on the signature pages hereof, (ii) in the case of any Lender, at its address or facsimile number set forth on its Administrative Questionnaire or (iii) in the case of any party, at such other address or facsimile number as such party may hereafter specify for the purpose by notice to the Administrative Agent and the Borrower in accordance with the provisions of this Section 13.1 . Each such notice, request or other communication shall be effective (x) if given by facsimile transmission, when transmitted to the facsimile number specified in this Section and confirmation of receipt is received, (y) if given by mail, 72 hours after such communication is deposited in the mails with first class postage prepaid, addressed as aforesaid, or (z) if given by any other means, when delivered (or, in the case of electronic transmission, received) at the address specified in this Section; provided that notices to the Administrative Agent under Article II shall not be effective until received.

13.2 Change of Address . The Borrower, the Administrative Agent and any Lender may each change the address for service of notice upon it by a notice in writing to the other parties hereto.

ARTICLE XIV

COUNTERPARTS; EFFECTIVENESS

This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one agreement, and any of the parties hereto may execute this Agreement by signing any such counterpart. This Agreement shall become effective when (a) it has been executed by the Borrower, the Administrative Agent and the Lenders and each party has notified the Administrative Agent by facsimile transmission or telephone that it has taken such action and (b) the Borrower has paid all outstanding fees and other amounts payable by the Borrower in connection with the termination of the Existing Credit Agreement. Delivery of an executed counterpart of a signature page of this Agreement by facsimile or in electronic format (e.g., “pdf” or “tif” file format) shall be effective as delivery of a manually executed counterpart of this Agreement.

ARTICLE XV

CHOICE OF LAW; CONSENT TO JURISDICTION; WAIVER OF JURY TRIAL

15.1 CHOICE OF LAW . THE RIGHTS AND DUTIES OF THE BORROWER, THE ADMINISTRATIVE AGENT AND THE LENDERS UNDER THIS AGREEMENT AND THE NOTES (INCLUDING MATTERS RELATING TO THE MAXIMUM PERMISSIBLE RATE), AND THE OTHER LOAN DOCUMENTS SHALL, PURSUANT TO NEW YORK GENERAL OBLIGATIONS LAW SECTION 5-1401, BE GOVERNED BY THE LAW OF THE STATE OF NEW YORK.

15.2 Consent To Jurisdiction . Any judicial proceeding brought against the Borrower with respect to any Loan Document Related Claim may be brought in any court of competent jurisdiction in The City of New York, and, by execution and delivery of this Agreement, the Borrower (a) accepts, generally and unconditionally, the exclusive jurisdiction of such courts and any related appellate court and irrevocably agrees to be bound by any judgment rendered thereby in connection with any Loan Document Related Claim and (b) irrevocably waives any objection it may now or hereafter have as to the venue of any such proceeding brought in such a court or that such a court is an inconvenient forum. The Borrower hereby waives personal service of process and consents that service of process upon it may be made by certified or registered mail, return receipt requested, at its address specified or determined in accordance with the provisions of Article XIII , and service so made shall be deemed completed on the third Business Day after such service is deposited in the mail. Nothing herein shall affect the right of the Administrative Agent, any Lender or any other Indemnified Person to serve process in any other manner permitted by law or shall limit the right of the Administrative Agent, the Syndication Agent, any Documentation Agent, any Lender or any other Indemnified Person to bring proceedings against the Borrower in the courts of any other jurisdiction. Any judicial proceeding by the Borrower against the Administrative Agent or any Lender involving any Loan Document Related Claim shall be brought only in a court located in the City and State of New York.

15.3 WAIVER OF JURY TRIAL . THE BORROWER, THE ADMINISTRATIVE AGENT AND EACH LENDER HEREBY WAIVE TRIAL BY JURY IN ANY JUDICIAL PROCEEDING INVOLVING ANY LOAN DOCUMENT RELATED CLAIM.

15.4 LIMITATION ON LIABILITY . TO THE EXTENT PERMITTED UNDER APPLICABLE LAW, NEITHER THE ADMINISTRATIVE AGENT, NOR THE LENDERS NOR ANY OTHER INDEMNIFIED PERSON SHALL HAVE ANY LIABILITY WITH RESPECT TO, AND THE BORROWER HEREBY WAIVES, RELEASES AND AGREES NOT TO SUE FOR, ANY SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES, AND TO THE EXTENT PERMITTED UNDER APPLICABLE LAW, PUNITIVE DAMAGES SUFFERED BY THE BORROWER IN CONNECTION WITH ANY LOAN DOCUMENT RELATED CLAIM.

15.5 USA PATRIOT ACT NOTICE . Each Lender and the Administrative Agent (for itself and not on behalf of any Lender) hereby notifies the Borrower that pursuant to the requirements of the USA Patriot Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)) (the “ Patriot Act ”), it is required to obtain, verify and record information that identifies the Borrower, which information includes the name and address of the Borrower and other information that will allow such Lender or Administrative Agent, as applicable, to identify the Borrower in accordance with the Patriot Act.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the Borrower, the Lenders and the Administrative Agent have executed this Agreement as of the date first above written.

WASHINGTON GAS LIGHT COMPANY

By: /s/ Anthony M. Nee
Anthony M. Nee
Treasurer

WELLS FARGO BANK, NATIONAL ASSOCIATION , as Administrative Agent, Issuing Bank, Swingline Lender and Lender

By: /s/ Allison Newman
Allison Newman
Director

THE BANK OF TOKYO-MITSUBISHI UFJ, LTD ., as Syndication Agent and Lender

By: /s/ Nicholas R. Battista
Nicholas R. Battista
Director

BRANCH BANKING AND TRUST COMPANY , as Co-Documentation Agent, Issuing Bank and Lender

By: /s/ Michael F. Skorich
Michael F. Skorich
Senior Vice President

TD BANK, N.A. , as Co-Documentation Agent and Lender

By: /s/ Vijay Prasad
Vijay Prasad
Senior Vice President

THE BANK OF NEW YORK MELLON , as Lender

By: /s/ Richard K. Fronapfel
Richard K. Fronapfel
Vice President

PNC BANK, NATIONAL ASSOCIATION, as Lender

By: /s/ Bremmer Kneib
Bremmer Kneib
Vice President

U.S. BANK, NATIONAL ASSOCIATION, as Lender

By: /s/ Holland H. Williams
Holland H. Williams
AVP

CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK AGENCY, as Lender

By: /s/ Robert W. Casey, Jr.
Robert W. Casey, Jr.
Executive Director

Robert Casey
Canadian Imperial Bank of Commerce
New York Agency Authorized signatory

CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK AGENCY , as Lender

By: /s/ Eoin Roche
Eoin Roche
Executive Director

Eoin Roche
Canadian Imperial Bank of Commerce
New York Agency
Authorized Signatory

THE NORTHERN TRUST COMPANY, as Lender

By: /s/ Lisa DeCristofaro
Lisa DeCristofaro
Vice President

MECHANICS AND FARMERS BANK, as Lender

By: /s/ James E. Sansom
James E. Sansom
SVP

Exhibit 31.1

CERTIFICATION OF WGL HOLDINGS, INC.

I, Terry D. McCallister, certify that:

1. I have reviewed this quarterly report on Form 10-Q of WGL Holdings, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/ Terry D. McCallister
Terry D. McCallister
Chairman and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF WGL HOLDINGS, INC.

I, Vincent L. Ammann, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of WGL Holdings, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors:
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 3, 2012

/s/ Vincent L. Ammann, Jr.
Vincent L. Ammann, Jr.
Vice President and Chief Financial Officer

Exhibit 31.3

CERTIFICATION OF WASHINGTON GAS LIGHT COMPANY

I, Terry D. McCallister, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Washington Gas Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors:
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 3, 2012

/s/ Terry D. McCallister
Terry D. McCallister
Chairman and Chief Executive Officer

Exhibit 31.4

CERTIFICATION OF WASHINGTON GAS LIGHT COMPANY

I, Vincent L. Ammann, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Washington Gas Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/ Vincent L. Ammann, Jr.
Vincent L. Ammann, Jr.
Vice President and Chief Financial Officer

Exhibit 32

CERTIFICATION OF THE CHAIRMAN AND CHIEF EXECUTIVE OFFICER AND THE VICE PRESIDENT AND CHIEF FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the combined Quarterly Report of WGL Holdings, Inc. and Washington Gas Light Company (the "Companies") on Form 10-Q for the quarterly period ended March 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Terry D. McCallister, Chairman and Chief Executive Officer of the Companies, and Vincent L. Ammann, Jr., Vice President and Chief Financial Officer of the Companies, each hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of their knowledge, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Companies.

This certification is being made for the exclusive purpose of compliance by the Chairman and Chief Executive Officer and the Vice President and Chief Financial Officer of the Companies with the requirements of Section 906 of the Sarbanes-Oxley Act of 2002, and may not be disclosed, distributed, or used by any person for any reason other than as specifically required by law.

/s/ Terry D. McCallister
Terry D. McCallister
Chairman and Chief Executive Officer

/s/ Vincent L. Ammann, Jr.
Vincent L. Ammann, Jr.
Vice President and Chief Financial Officer

May 3, 2012

WISCONSIN ENERGY CORP (WEC)

10-Q
Quarterly report pursuant to sections 13 or 15(d)
Filed on 05/03/2012
Filed Period 03/31/2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended **March 31, 2012**

Commission File Number	Registrant; State of Incorporation Address; and Telephone Number	IRS Employer Identification No.
001-09057	**WISCONSIN ENERGY CORPORATION** (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 1331 Milwaukee, WI 53201 (414) 221-2345	39-1391525

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X]   No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).   Yes [X]   No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).   Yes [ ]   No [X]

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (March 31, 2012):

Common Stock, $.01 Par Value,	230,455,017 shares outstanding.

WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED MARCH 31, 2012

TABLE OF CONTENTS

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below:

Primary Subsidiaries	
We Power	W.E. Power, LLC
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC
Significant Assets	
OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
VAPP	Valley Power Plant
Other Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
ERGSS	Elm Road Generating Station Supercritical, LLC
Federal and State Regulatory Agencies	
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPSC	Michigan Public Service Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources
Environmental Terms	
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
NOV	Notice of Violation
NO_x	Nitrogen Oxide
SO_2	Sulfur Dioxide
Other Terms and Abbreviations	
AQCS	Air Quality Control System
Compensation Committee	Compensation Committee of the Board of Directors
ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
FTRs	Financial Transmission Rights
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 issued in May 2007

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below:

MISO	Midwest Independent Transmission System Operator, Inc.
NDAA	National Defense Authorization Act
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	*Power the Future*
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.

Measurements

Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
MW	Megawatt(s) (One MW equals one million Watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (Exchange Act). These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of construction projects, regulatory matters, on-going legal proceedings, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets" or similar terms or variations of these terms.

Actual results may differ materially from those set forth in forward-looking statements. In addition to the assumptions and other factors referred to specifically in connection with these statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statements or otherwise affect our future results of operations and financial condition include, among others, the following:

- Factors affecting utility operations such as catastrophic weather-related or terrorism-related damage; cyber-security threats and disruptions to our technology network; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; unanticipated changes in the cost or availability of materials needed to operate new environmental controls at our electric generating facilities or replace and/or repair our electric and gas distribution systems; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; or inflation rates.

- Factors affecting the demand for electricity and natural gas, including weather and other natural phenomena; the economic climate in our service territories; customer growth and declines; customer business conditions, including demand for their products and services; and energy conservation efforts.

- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery of all costs associated with our *Power the Future* (PTF) strategy, as well as costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midwest Independent Transmission System Operator, Inc. (MISO) Energy Markets.

- Increased competition in our electric and gas markets and continued industry consolidation.

- The ability to control costs and avoid construction delays during the development and construction of new environmental controls and renewable generation.

- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; electric and gas industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; any required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities or cybersecurity threats; required approvals for new construction, and the siting approval process for new generation and transmission facilities and new pipeline construction; changes to the Federal Power Act and related regulations and enforcement thereof by the Federal Energy Regulatory Commission (FERC) and other regulatory agencies; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; changes in the application of existing laws and regulations; and changes in the interpretation or enforcement of permit conditions by the permitting agencies.

- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION -- (CONT'D)

- Current and future litigation, regulatory investigations, proceedings or inquiries, including FERC matters and Internal Revenue Service (IRS) audits and other tax matters.

- Events in the global credit markets that may affect the availability and cost of capital.

- Other factors affecting our ability to access the capital markets, including general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or any of our subsidiaries; and our credit ratings.

- The investment performance of our pension and other post-retirement benefit trusts.

- The financial performance of American Transmission Company LLC (ATC) and its corresponding contribution to our earnings.

- The impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act and any regulations promulgated thereunder.

- The impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 and any related regulations.

- The effect of accounting pronouncements issued periodically by standard setting bodies, including any changes in regulatory accounting policies and practices and any requirement for U.S. registrants to follow International Financial Reporting Standards instead of Generally Accepted Accounting Principles (GAAP).

- Unanticipated technological developments that result in competitive disadvantages and create the potential for impairment of existing assets.

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading markets and fuel suppliers and transporters.

- The ability to obtain and retain short- and long-term contracts with wholesale customers.

- The cyclical nature of property values that could affect our real estate investments.

- Changes to the legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law.

- Foreign governmental, economic, political and currency risks.

- Other business or investment considerations that may be disclosed from time to time in our Securities and Exchange Commission (SEC) filings or in other publicly disseminated written documents, including the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2011.

We expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

INTRODUCTION

Wisconsin Energy Corporation is a diversified holding company which conducts its operations primarily in two operating segments: a utility energy segment and a non-utility energy segment. Unless qualified by their context when used in this document, the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of its subsidiaries. Our primary subsidiaries are Wisconsin Electric Power Company (Wisconsin Electric), Wisconsin Gas LLC (Wisconsin Gas) and W.E. Power, LLC (We Power).

Utility Energy Segment: Our utility energy segment consists of: Wisconsin Electric, which serves electric customers in Wisconsin and the Upper Peninsula of Michigan, gas customers in Wisconsin and steam customers in metropolitan Milwaukee, Wisconsin; and Wisconsin Gas, which serves gas customers in Wisconsin. Wisconsin Electric and Wisconsin Gas operate under the trade name of "We Energies."

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Item 1. Business and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2011 Annual Report on Form 10-K for more information on PTF.

We have prepared the unaudited interim financial statements presented in this Form 10-Q pursuant to the rules and regulations of the SEC. We have condensed or omitted some information and note disclosures normally included in financial statements prepared in accordance with GAAP pursuant to these rules and regulations. This Form 10-Q, including the financial statements contained herein, should be read in conjunction with our 2011 Annual Report on Form 10-K, including the financial statements and notes therein.

PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	Three Months Ended March 31	
	2012	2011
	(Millions of Dollars, Except Per Share Amounts)	
Operating Revenues	$ 1,191.2	$ 1,328.7
Operating Expenses		
Fuel and purchased power	253.8	267.6
Cost of gas sold	237.5	342.4
Other operation and maintenance	286.3	313.5
Depreciation and amortization	87.6	81.3
Property and revenue taxes	30.3	28.3
Total Operating Expenses	895.5	1,033.1
Operating Income	295.7	295.6
Equity in Earnings of Transmission Affiliate	15.6	15.5
Other Income, net	16.0	12.5
Interest Expense, net	58.9	63.4
Income Before Income Taxes	268.4	260.2
Income Tax Expense	96.3	89.3
Net Income	$ 172.1	$ 170.9
Earnings Per Share		
Basic	$ 0.75	$ 0.73
Diluted	$ 0.74	$ 0.72
Weighted Average Common Shares Outstanding (Millions)		
Basic	230.5	233.7
Diluted	233.2	236.6
Dividends Per Share of Common Stock	$ 0.30	$ 0.26

The accompanying Notes to Consolidated Condensed Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED BALANCE SHEETS

(Unaudited)

	March 31, 2012	December 31, 2011
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$ 13,485.5	$ 12,977.7
Accumulated depreciation	(3,855.5)	(3,797.8)
	9,630.0	9,179.9
Construction work in progress	547.3	921.3
Leased facilities, net	57.7	59.2
Net Property, Plant and Equipment	10,235.0	10,160.4
Investments		
Equity investment in transmission affiliate	355.0	349.7
Other	38.4	43.6
Total Investments	393.4	393.3
Current Assets		
Cash and cash equivalents	18.1	14.1
Restricted cash	24.7	45.5
Accounts receivable, net	386.9	349.4
Accrued revenues	190.3	252.7
Materials, supplies and inventories	311.6	382.0
Prepayments and other	348.2	382.5
Total Current Assets	1,279.8	1,426.2
Deferred Charges and Other Assets		
Regulatory assets	1,286.3	1,238.7
Goodwill	441.9	441.9
Other	184.9	201.6
Total Deferred Charges and Other Assets	1,913.1	1,882.2
Total Assets	$ 13,821.3	$ 13,862.1
Capitalization and Liabilities		
Capitalization		
Common equity	$ 4,051.5	$ 3,963.3
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,602.8	4,614.3
Total Capitalization	8,684.7	8,608.0
Current Liabilities		
Long-term debt due currently	33.8	32.6
Short-term debt	557.3	669.9
Accounts payable	239.3	325.7
Accrued payroll and vacation	78.9	105.9
Other	262.6	230.4
Total Current Liabilities	1,171.9	1,364.5
Deferred Credits and Other Liabilities		
Regulatory liabilities	911.6	902.0
Deferred income taxes - long-term	1,791.2	1,696.1
Deferred revenue, net	740.9	754.5

Pension and other benefit obligations	221.0	222.7
Other	300.0	314.3
Total Deferred Credits and Other Liabilities	3,964.7	3,889.6
Total Capitalization and Liabilities	$ 13,821.3	$ 13,862.1

The accompanying Notes to Consolidated Condensed Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31	
	2012	2011
	(Millions of Dollars)	
Operating Activities		
Net income	$ 172.1	$ 170.9
Reconciliation to cash		
Depreciation and amortization	90.6	84.2
Deferred income taxes and investment tax credits, net	67.9	71.9
Contributions to qualified benefit plans	—	(122.4)
Change in - Accounts receivable and accrued revenues	11.5	(40.9)
Inventories	70.4	94.7
Other current assets	29.8	33.0
Accounts payable	(82.3)	(48.4)
Accrued income taxes, net	15.5	39.7
Other current liabilities	15.2	61.6
Other, net	(50.2)	46.7
Cash Provided by Operating Activities	340.5	391.0
Investing Activities		
Capital expenditures	(142.3)	(135.5)
Investment in transmission affiliate	(2.6)	(2.6)
Proceeds from asset sales	2.7	38.3
Change in restricted cash	20.8	(37.2)
Other, net	(9.0)	(7.4)
Cash Used in Investing Activities	(130.4)	(144.4)
Financing Activities		
Exercise of stock options	12.9	13.0
Purchase of common stock	(29.2)	(24.9)
Dividends paid on common stock	(69.1)	(60.8)
Issuance of long-term debt	—	420.0
Retirement and repurchase of long-term debt	(8.0)	(5.0)
Change in short-term debt	(112.6)	(376.4)
Other, net	(0.1)	(1.0)
Cash Used in Financing Activities	(206.1)	(35.1)
Change in Cash and Cash Equivalents	4.0	211.5
Cash and Cash Equivalents at Beginning of Period	14.1	24.5
Cash and Cash Equivalents at End of Period	$ 18.1	$ 236.0

The accompanying Notes to Consolidated Condensed Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
(Unaudited)

1 -- GENERAL INFORMATION

Our accompanying unaudited consolidated condensed financial statements should be read in conjunction with Item 8, Financial Statements and Supplementary Data, in our 2011 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary for a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three months ended March 31, 2012 are not necessarily indicative of the results which may be expected for the entire fiscal year 2012 because of seasonal and other factors.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Presentation of Comprehensive Income: In June 2011, the Financial Accounting Standards Board (FASB) issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of changes in stockholders' equity. The guidance gives entities the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued an amendment to indefinitely defer one of the requirements contained in its June 2011 final standard. That requirement called for reclassification adjustments from accumulated other comprehensive income to be measured and presented by income statement line item in net income and also in other comprehensive income. This guidance, including the related deferral, is effective for fiscal years and interim periods beginning after December 15, 2011 and must be applied retrospectively. We adopted this guidance on January 1, 2012, and it did not have any material impact on us.

Fair Value Measurement: In May 2011, the FASB issued guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. Under the new guidance, required disclosures are expanded, particularly for fair value measurements that are categorized within Level 3 of the fair value hierarchy, for which quantitative information about the unobservable inputs, the valuation processes used by the entity, and the sensitivity of the measurement to the unobservable inputs will be required. Entities are also required to disclose the categorization, by level of the fair value hierarchy, of items that are not measured at fair value in the balance sheets but for which the fair value is required to be disclosed. This guidance is effective for fiscal years and interim periods beginning after December 15, 2011 and must be applied prospectively. We adopted this guidance on January 1, 2012, and it did not have any material impact on us.

3 -- COMMON EQUITY

Share-Based Compensation Expense: For additional information on share-based compensation, including stock options, restricted stock and performance units, see Note I -- Common Equity in our 2011 Annual Report on Form 10-K. We utilize the straight-line attribution method for recognizing share-based compensation expense. Accordingly, for employee awards, equity classified share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as expense over the requisite service period. There were no modifications to outstanding stock options during the period. Shares purchased on the open market by our independent agents are currently used to satisfy share-based awards.

The following table summarizes recorded pre-tax share-based compensation expense and the related tax benefit for share-based awards made to our employees and directors:

	Three Months Ended March 31	
	2012	2011
	(Millions of Dollars)	
Performance units	$ 11.8	$ 1.0
Stock options	0.7	0.6
Restricted stock	0.8	0.5
Share-based compensation expense	$ 13.3	$ 2.1
Related Tax Benefit	$ 5.3	$ 0.8

Stock Option Activity: During the first three months of 2012, the Compensation Committee granted 938,770 non-qualified stock options that had an estimated fair value of $3.34 per share. During the first three months of 2011, the Compensation Committee granted 458,180 non-qualified stock options that had an estimated fair value of $3.17 per share. The following assumptions were used to value the options using a binomial option pricing model:

	2012	2011
Risk-free interest rate	0.1% - 2.0%	0.2% - 3.4%
Dividend yield	3.9%	3.9%
Expected volatility	19.0%	19.0%
Expected forfeiture rate	2.0%	2.0%
Expected life (years)	5.9	5.5

The risk-free interest rate is based on the U.S. Treasury interest rate whose term is consistent with the expected life of the stock options. Dividend yield, expected volatility, expected forfeiture rate and expected life assumptions are based on our historical experience.

The following is a summary of our stock option activity for the three months ended March 31, 2012:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2012	10,638,750	$ 21.65		
Granted	938,770	$ 34.88		
Exercised	(718,669)	$ 18.01		
Forfeited	(7,720)	$ 26.94		
Outstanding as of March 31, 2012	10,851,131	$ 23.03	5.7	$ 131.8
Exercisable as of March 31, 2012	9,118,361	$ 21.52	5.0	$ 124.5

The intrinsic value of options exercised was $12.0 million and $9.1 million for the three months ended March 31, 2012 and 2011, respectively. Cash received from options exercised was $12.9 million and $13.0 million for the three months ended March 31, 2012 and 2011, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was zero and approximately $3.6 million, respectively.

All outstanding stock options to purchase shares of common stock were included in the computation of diluted earnings per share during the first quarter of 2012.

The following table summarizes information about stock options outstanding as of March 31, 2012:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$12.71 to $19.74	2,750,199	$ 17.81	2.9	2,750,199	$ 17.81	2.9
$21.11 to $24.92	6,713,942	$ 23.09	6.0	6,257,402	$ 22.96	5.9
$29.35 to $34.88	1,386,990	$ 33.09	9.4	110,760	$ 32.59	9.3
	10,851,131	$ 23.03	5.7	9,118,361	$ 21.52	5.0

The following table summarizes information about our non-vested options during the three months ended March 31, 2012:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of January 1, 2012	3,103,770	$ 3.78
Granted	938,770	$ 3.34
Vested	(2,302,050)	$ 3.96
Forfeited	(7,720)	$ 3.25
Non-vested as of March 31, 2012	1,732,770	$ 3.31

As of March 31, 2012, total compensation costs related to non-vested stock options not yet recognized was approximately $3.0 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

Restricted Shares: During the first three months of 2012 , the Compensation Committee granted 94,959 restricted shares to directors, officers and other key employees. These awards have a three-year vesting period, and generally, one-third of the award vests on each anniversary of the grant date. During the vesting period, restricted share recipients have voting rights and are entitled to dividends in the same manner as other shareholders.

The following restricted stock activity occurred during the three months ended March 31, 2012:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of January 1, 2012	192,558	
Granted	94,959	$ 34.46
Released	(72,660)	$ 33.09
Forfeited	(3,945)	$ 30.81
Outstanding as of March 31, 2012	210,912	

We record the market value of the restricted stock awards on the date of grant, and then we charge their value to expense over the vesting period of the awards. The intrinsic value of restricted stock vesting was $2.6 million and $2.1 million for the three months ended March 31, 2012 and 2011, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was zero and $0.6 million for the three months ended March 31, 2012 and 2011, respectively.

As of March 31, 2012 , total compensation cost related to restricted stock not yet recognized was approximately $4.8 million , which is expected to be recognized over the next 27 months on a weighted-average basis.

Performance Units: In January 2012 and 2011, the Compensation Committee granted 346,570 and 435,690 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing compensation costs over the three-year period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2011 and 2010 vested and were settled during the first quarter of 2012 and 2011, and had a total intrinsic value of $26.7 million and $12.6 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $9.7 million and $4.3 million, respectively. As of March 31, 2012, total compensation cost related to performance units not yet recognized was approximately $28.6 million, which is expected to be recognized over the next 22 months on a weighted-average basis.

Restrictions: Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its non-utility subsidiary, We Power, and its utility subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note I -- Common Equity in our 2011 Annual Report on Form 10-K for additional information on these and other restrictions.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

Comprehensive Income: Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to owners.

There was no material other comprehensive income for the three months ended March 31, 2012 or 2011.

Share Repurchase Program: In May 2011, our Board of Directors authorized a share repurchase program that allows us to repurchase up to $300 million of our common stock through the end of 2013. Through March 31, 2012, we have repurchased $100.0 million of our common stock pursuant to this program at an average cost of $30.79 per share. The share repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. In addition, through our independent agents, we purchase shares on the open market to fulfill exercised stock options and restricted stock awards. The following table identifies the shares purchased by the company in the following periods:

	Three Months Ended March 31			
	2012		2011	
	Shares	Cost	Shares	Cost
	(In Millions)			
Under May 2011 share repurchase program	—	$ —	—	$ —
To fulfill exercised stock options and restricted stock awards	0.8	$ 28.3	0.8	$ 24.2
Total	0.8	$ 28.3	0.8	$ 24.2

4 -- DIVESTITURES

Edgewater Generating Unit 5: On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp. (WPL) for our net book value, including working capital, of approximately $38 million . This transaction was treated as a sale of an asset.

5 -- LONG-TERM DEBT

In January 2011, we issued a total of $420 million of long-term debt ($205 million aggregate principal amount of 4.673% Series B Senior Notes due January 19, 2031 and $215 million aggregate principal amount of 5.848% Series B Senior Notes due January 19, 2041) and used the net proceeds to repay short-term debt incurred to finance the construction of Oak Creek expansion Unit 2 (OC 2) and for other corporate purposes. The Series B Senior Notes are secured by a collateral assignment of the leases between Elm Road Generating Station

Supercritical, LLC (ERGSS) and Wisconsin Electric related to OC 2.

On April 1, 2011, we used cash and short-term borrowings to retire $450 million of long-term debt that matured.

6 -- FAIR VALUE MEASUREMENTS

Fair value measurements require enhanced disclosures about assets and liabilities that are measured and reported at fair value and establish a hierarchal disclosure framework which prioritizes and ranks the level of observable inputs used in measuring fair value.

Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily apply the market approach for recurring fair value measurements and attempt to utilize the best available information. Accordingly, we also utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities measured and reported at fair value are classified and disclosed in one of the following categories:

Level 1 -- Pricing inputs are unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Instruments in this category consist of financial instruments such as exchange-traded derivatives, cash equivalents and restricted cash investments.

Level 2 -- Pricing inputs are other than quoted prices in active markets, which are either directly or indirectly observable as of the reporting date, and fair value is determined through the use of models or other valuation methodologies. Instruments in this category include non-exchange-traded derivatives such as Over-the-Counter (OTC) forwards and options.

Level 3 -- Pricing inputs include significant inputs that are generally less observable from objective sources. The inputs in the determination of fair value require significant management judgment or estimation. At each balance sheet date, we perform an analysis of all instruments subject to fair value reporting and include in Level 3 all instruments whose fair value is based on significant unobservable inputs.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, an instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the instrument.

The following tables summarize our financial assets and liabilities by level within the fair value hierarchy:

Recurring Fair Value Measures	As of March 31, 2012			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$ 24.7	$ —	$ —	$ 24.7
Derivatives	0.9	12.3	2.2	15.4
Total	$ 25.6	$ 12.3	$ 2.2	$ 40.1
Liabilities:				
Derivatives	$ 12.3	$ 0.3	$ —	$ 12.6
Total	$ 12.3	$ 0.3	$ —	$ 12.6

Recurring Fair Value Measures	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$ 45.5	$ —	$ —	$ 45.5
Derivatives	0.3	14.6	5.7	20.6
Total	$ 45.8	$ 14.6	$ 5.7	$ 66.1
Liabilities:				
Derivatives	$ 8.2	$ 1.0	$ —	$ 9.2
Total	$ 8.2	$ 1.0	$ —	$ 9.2

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the settlement we received from the United States Department of Energy (DOE) during the first quarter of 2011, which is being returned, net of costs incurred, to customers. Derivatives reflect positions we hold in exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within Level 1. Some OTC derivative contracts are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets utilizing a mid-market pricing convention (the mid-point between bid and ask prices), as appropriate. In such cases, these derivatives are classified within Level 2. Certain OTC derivatives may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives are in less active markets with a lower availability of pricing information which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy:

	2012	2011
	(Millions of Dollars)	
Balance as of January 1	$ 5.7	$ 5.9
Realized and unrealized gains (losses)	—	—
Purchases	—	—
Issuances	—	—
Settlements	(3.5)	(3.8)
Transfers in and/or out of Level 3	—	—
Balance as of March 31	$ 2.2	$ 2.1
Change in unrealized gains (losses) relating to instruments still held as of March 31	$ —	$ —

Derivative instruments reflected in Level 3 of the hierarchy include MISO Financial Transmission Rights (FTRs) that are measured at fair value each reporting period using monthly or annual auction shadow prices from relevant auctions. Changes in fair value for Level 3 recurring items are recorded on our balance sheet. See Note 7 -- Derivative Instruments for further information on the offset to regulatory assets and liabilities.

The carrying amount and estimated fair value of certain of our recorded financial instruments are as follows:

	March 31, 2012		December 31, 2011	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$ 30.4	$ 25.0	$ 30.4	$ 25.1
Long-term debt, including current portion	$ 4,533.4	$ 5,077.0	$ 4,541.4	$ 5,179.9

The carrying value of net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short-term nature of these instruments. The fair value of our preferred stock is estimated based upon the quoted market value for the same or similar issues. The fair value of our long-term debt, including the current portion of long-term debt, but excluding capitalized leases and unamortized discount on debt, is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. Based on these assessments, the above items have been classified within Level 2.

7 -- DERIVATIVE INSTRUMENTS

We utilize derivatives as part of our risk management program to manage the volatility and costs of purchased power, generation and natural gas purchases for the benefit of our customers and shareholders. Our approach is non-speculative and designed to mitigate risk and protect against price volatility. Regulated hedging programs require prior approval by the Public Service Commission of Wisconsin (PSCW).

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of March 31, 2012, we recognized $27.6 million in regulatory assets and $16.3 million in regulatory liabilities related to derivatives in comparison to $29.6 million in regulatory assets and $21.7 million in regulatory liabilities as of December 31, 2011.

We record our current derivative assets on the balance sheet in prepayments and other current assets and the current portion of the liabilities in other current liabilities. We had no long-term portion of derivative assets as of March 31, 2012, and the long-term portion of our derivative liabilities of $0.3 million is recorded in other deferred credits and other liabilities as of March 31, 2012. Our Consolidated Condensed Balance Sheets as of March 31, 2012 and December 31, 2011 include:

	March 31, 2012		December 31, 2011	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$ 2.5	$ 12.6	$ 2.1	$ 9.1
Fuel Oil	0.9	—	0.3	0.1
FTRs	2.2	—	5.7	—
Coal	9.8	—	12.5	—
Total	$ 15.4	$ 12.6	$ 20.6	$ 9.2

Our Consolidated Condensed Income Statements include gains (losses) on derivative instruments used in our risk management strategies under fuel and purchased power for those commodities supporting our electric operations and under cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) were as follows:

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	20.4 million Dth	$ (16.2)	19.4 million Dth	$ (10.6)
Fuel Oil	1.7 million gallons	0.6	3.2 million gallons	0.4
FTRs	5,358 MW	0.6	6,352 MW	3.8
Total		$ (15.0)		$ (6.4)

As of March 31, 2012 and December 31, 2011, we posted collateral of $16.1 million and $11.9 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

8 -- BENEFITS

The components of our net periodic pension and Other Post-Retirement Employee Benefits (OPEB) costs for the three months ended March 31 were as follows:

	Pension Costs	
Benefit Plan Cost Components	2012	2011
	(Millions of Dollars)	
Net Periodic Benefit Cost		
Service cost	$ 5.4	$ 4.6
Interest cost	16.4	16.7
Expected return on plan assets	(22.6)	(20.7)
Amortization of:		
Prior service cost	0.6	0.6
Actuarial loss	9.9	8.1
Net Periodic Benefit Cost	$ 9.7	$ 9.3

	OPEB Costs	
Benefit Plan Cost Components	2012	2011
	(Millions of Dollars)	
Net Periodic Benefit Cost		
Service cost	$ 2.8	$ 2.8
Interest cost	5.1	5.3
Expected return on plan assets	(4.8)	(4.3)
Amortization of:		
Transition obligation	0.1	0.1
Prior service (credit)	(0.5)	(0.5)
Actuarial loss	1.8	1.5
Net Periodic Benefit Cost	$ 4.5	$ 4.9

During the first quarter of 2011, we contributed $122.4 million to our qualified benefit plans. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $5.2 million as of March 31, 2012 and $15.3 million as of December 31, 2011 .

9 -- SEGMENT INFORMATION

Summarized financial information concerning our operating segments for the three months ended March 31, 2012 and 2011 is shown in the following table:

Three Months Ended	Operating Segments — Energy — Utility	Operating Segments — Energy — Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
			(Millions of Dollars)		
March 31, 2012					
Operating Revenues (b)	$ 1,178.4	$ 107.3	$ 0.3	$ (94.8)	$ 1,191.2
Other Operation and Maintenance	$ 376.4	$ 2.1	$ 1.3	$ (93.5)	$ 286.3
Depreciation and Amortization	$ 70.7	$ 16.8	$ 0.1	$ —	$ 87.6
Operating Income (Loss)	$ 208.6	$ 88.4	$ (1.3)	$ —	$ 295.7
Equity in Earnings of Unconsolidated Affiliates	$ 15.6	$ —	$ —	$ —	$ 15.6
Interest Expense, Net	$ 29.2	$ 16.8	$ 13.1	$ (0.2)	$ 58.9
Income Tax Expense (Benefit)	$ 74.0	$ 28.8	$ (6.5)	$ —	$ 96.3
Net Income (Loss)	$ 136.2	$ 43.0	$ 172.6	$ (179.7)	$ 172.1
Capital Expenditures	$ 137.6	$ 1.9	$ 2.8	$ —	$ 142.3
Total Assets (c)	$ 13,429.0	$ 2,932.6	$ 4,771.9	$ (7,312.2)	$ 13,821.3
March 31, 2011					
Operating Revenues (b)	$ 1,316.5	$ 103.2	$ 0.2	$ (91.2)	$ 1,328.7
Other Operation and Maintenance	$ 400.9	$ 1.5	$ 1.1	$ (90.0)	$ 313.5
Depreciation and Amortization	$ 63.4	$ 17.7	$ 0.2	$ —	$ 81.3
Operating Income (Loss)	$ 213.0	$ 84.0	$ (1.4)	$ —	$ 295.6
Equity in Earnings of Unconsolidated Affiliates	$ 15.5	$ —	$ (0.1)	$ —	$ 15.4
Interest Expense, Net	$ 28.1	$ 15.9	$ 19.5	$ (0.1)	$ 63.4
Income Tax Expense (Benefit)	$ 71.3	$ 27.7	$ (9.7)	$ —	$ 89.3
Net Income (Loss)	$ 141.0	$ 40.5	$ 170.8	$ (181.4)	$ 170.9
Capital Expenditures	$ 127.2	$ 8.2	$ 0.1	$ —	$ 135.5
Total Assets (c)	$ 12,632.8	$ 2,975.9	$ 4,913.6	$ (7,333.7)	$ 13,188.6

(a) Corporate & Other includes all other non-utility activities, primarily non-utility real estate investment and development by Wispark as well as interest on corporate debt.

(b) An elimination for intersegment revenues is included in Operating Revenues. This elimination is primarily between We Power and Wisconsin Electric.

(c) An elimination of $2,355.9 million and $2,437.8 million is included in Total Assets as of March 31, 2012 and 2011, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

10 -- VARIABLE INTEREST ENTITIES

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. Certain disclosures are required by sponsors, significant interest holders in variable interest entities and potential variable interest entities.

We assess our relationships with potential variable interest entities such as our coal suppliers, natural gas suppliers, coal and gas transporters, and other counterparties in power purchase agreements and joint ventures. In making this assessment, we consider the potential that our contracts or other arrangements provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of the entity, the ability to directly or indirectly make decisions about the entities' activities and other factors.

We have identified two tolling and purchased power agreements with third parties that represent variable interests. We account for one of these agreements, with an independent power producer, as an operating lease. The agreement has a remaining term of approximately one year. We have examined the risks of the entity including the impact of operations and maintenance, dispatch, financing, fuel costs, remaining useful life and other factors, and have determined that we are not the primary beneficiary of this entity. We have concluded that we do not have the power to direct the activities that would most significantly affect the economic performance of the entity over its remaining life.

We also have a purchased power agreement for 236 MW of firm capacity from a gas-fired cogeneration facility, which we account for as a capital lease. The agreement includes no minimum energy requirements over the remaining term of approximately 10 years. We have examined the risks of the entity including operations and maintenance, dispatch, financing, fuel costs and other factors, and have determined that we are not the primary beneficiary of the entity. We do not hold an equity or debt interest in the entity and there is no residual guarantee associated with the purchased power agreement.

We have approximately $296.7 million of required payments over the remaining term of these agreements. We believe that the required lease payments under these contracts will continue to be recoverable in rates. Total capacity and lease payments under these contracts for the three months ended March 31, 2012 and 2011 were $14.7 million and $15.0 million , respectively. Our maximum exposure to loss is limited to the capacity payments under the contracts.

11 -- COMMITMENTS AND CONTINGENCIES

Environmental Matters: We periodically review our exposure for environmental remediation costs as evidence becomes available indicating that our liability has changed. Given current information, including the following, we believe that future costs in excess of the amounts accrued and/or disclosed on all presently known and quantifiable environmental contingencies will not be material to our financial position or results of operations.

We have a program of comprehensive environmental remediation planning for former manufactured gas plant sites and coal combustion product disposal sites. We perform ongoing assessments of manufactured gas plant sites and related disposal sites used by Wisconsin Electric and Wisconsin Gas, and coal combustion product disposal/landfill sites used by Wisconsin Electric, as discussed below. We are working with the Wisconsin Department of Natural Resources (WDNR) in our investigation and remediation planning. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

Manufactured Gas Plant Sites: We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon on-going analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $21 million to $65 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of March 31, 2012, we have established reserves of $37.5 million related to future remediation costs.

Historically, the PSCW has allowed Wisconsin utilities, including Wisconsin Electric and Wisconsin Gas, to defer the costs spent on the remediation of manufactured gas plant sites, and has allowed for these costs to be recovered in rates over five years. Accordingly, we have recorded a regulatory asset for remediation costs.

Valley Power Plant Title V Air Permit: The WDNR renewed Valley Power Plant's (VAPP) Title V operating permit in February 2011. The term of the permit is five years. Sierra Club and Clean Wisconsin requested and were granted an administrative hearing before the WDNR on certain conditions of the permit. We filed a motion for partial summary judgment in that proceeding on March 22, 2012. If the case proceeds to hearing, it would be held in early 2013. The Sierra Club petitioned the United States Environmental Protection Agency (EPA) for additional reductions and monitoring for particulate matter, and revisions to certain applicable requirements. No timeline has been set by the EPA to respond to that petition.

We believe that the permit was properly issued and that the plant is in compliance with all applicable regulations and standards. However, if as a result of either proceeding the permit is remanded to the WDNR, the plant will continue to operate under the previous operating permit.

We filed an application with the PSCW in December 2011 for authority to replace and upgrade the Lincoln Arthur natural gas main, which would also have the capability to accommodate the increased natural gas required if VAPP were to convert from coal to natural gas. Clean Wisconsin has requested intervenor status in the PSCW process.

We also submitted a letter to the EPA in December 2011 with four voluntary goals which include: (1) reducing annual Sulfur Dioxide (SO_2) emissions from the plant to no more than 4,500 tons (a 65% decrease from 2001 emission levels); (2) installing a dry sorbent injection system that is needed to meet the utility Maximum Achievable Control Technology (MACT) rules earlier than the rules require if the installation would provide a direct economic benefit to customers and is approved by the PSCW; (3) holding an open house and tour of VAPP in 2012 to help inform the community on the plant, the unique role that it plays in the community, and to share environmental successes and future plans; and (4) converting VAPP to natural gas fuel by the 2017/2018 timeframe, provided we can demonstrate a direct economic benefit to customers and obtain authorization from the PSCW to do so.

Divested Assets: Pursuant to the sale of the Point Beach Nuclear Power Plant (Point Beach), we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We also provided customary indemnifications to WPL in connection with the sale of our interest in Edgewater Generating Unit 5. We have established reserves as deemed appropriate for these indemnification provisions.

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Wisconsin Energy Corporation Retirement Account Plan (Plan) in the U.S. District Court for the Eastern District of Wisconsin. The complaint alleged that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of the Employee Retirement Income Security Act of 1974 (ERISA) and were owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant.

In November 2011, we entered into a settlement agreement with the plaintiffs for $45.0 million, and the court promptly issued an order preliminarily approving the settlement. As part of the settlement agreement, we agreed to class certification for all similarly situated plaintiffs. The resolution of this matter resulted in a cost of less than $0.04 per share for 2011 after considering insurance and reserves established in the prior year. The court approved the settlement on April 3, 2012 and issued its written order on April 20, 2012. The plaintiffs have 30 days from the date of the written order to appeal this decision.

We do not anticipate further charges as a result of the settlement, other than certain process-related costs we expect to incur to implement the settlement.

Income Taxes: During the first quarter of 2012, the IRS issued guidance applicable to taxpayers that have taken positions within prior year tax returns relating to the conversion of capitalized assets to repair expense. As a result of this guidance, we have decreased our unrecognized tax benefits by approximately $7.4 million, exclusive of accrued interest.

12 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the three months ended March 31, 2012 , we paid $26.5 million in interest, net of amounts capitalized, and paid $15.3 million in income taxes, net of refunds. During the three months ended March 31, 2011 , we paid $12.5 million in interest, net of amounts capitalized, and received $24.8 million in net refunds from income taxes.

As of March 31, 2012 and 2011, the amount of accounts payable related to capital expenditures was $12.6 million and $20.6 million, respectively.

During the three months ended March 31, 2012 and 2011, total amortization of deferred revenue was $13.7 million and $13.2 million, respectively.

During the three months ended March 31, 2012 and 2011, our equity in earnings from ATC was $15.6 million and $15.5 million, respectively. During the three months ended March 31, 2012 and 2011, distributions received from ATC were $12.9 million and $12.4 million, respectively.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

RESULTS OF OPERATIONS -- THREE MONTHS ENDED MARCH 31, 2012

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first quarter of 2012 with the first quarter of 2011, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended March 31		
	2012	B (W)	2011
		(Millions of Dollars)	
Utility Energy Segment	$ 208.6	$ (4.4)	$ 213.0
Non-Utility Energy Segment	88.4	4.4	84.0
Corporate and Other	(1.3)	0.1	(1.4)
Total Operating Income	295.7	0.1	295.6
Equity in Earnings of Transmission Affiliate	15.6	0.1	15.5
Other Income, net	16.0	3.5	12.5
Interest Expense, net	58.9	4.5	63.4
Income Before Income Taxes	268.4	8.2	260.2
Income Tax Expense	96.3	(7.0)	89.3
Net Income	$ 172.1	$ 1.2	$ 170.9
Diluted Earnings Per Share	$ 0.74	$ 0.02	$ 0.72

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $208.6 million of operating income during the first quarter of 2012, a decrease of $4.4 million, or 2.1%, compared with the first quarter of 2011. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended March 31		
Utility Energy Segment	2012	B (W)	2011
		(Millions of Dollars)	
Operating Revenues			
Electric	$ 777.3	$ 0.7	$ 776.6
Gas	388.5	(136.2)	524.7
Other	12.6	(2.6)	15.2
Total Operating Revenues	1,178.4	(138.1)	1,316.5
Fuel and Purchased Power	255.1	13.7	268.8
Cost of Gas Sold	237.5	104.9	342.4
Gross Margin	685.8	(19.5)	705.3
Other Operating Expenses			
Other Operation and Maintenance	376.4	24.5	400.9
Depreciation and Amortization	70.7	(7.3)	63.4
Property and Revenue Taxes	30.1	(2.1)	28.0
Total Operating Expenses	969.8	133.7	1,103.5
Operating Income	$ 208.6	$ (4.4)	$ 213.0

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first quarter of 2012 with the first quarter of 2011:

	Electric Revenues			MWh Sales		
Electric Utility Operations	2012	B (W)	2011	2012	B (W)	2011
		(Millions of Dollars)			(Thousands)	
Customer Class						
Residential	$ 274.6	$ (8.4)	$ 283.0	1,942.9	(87.1)	2,030.0
Small Commercial/Industrial	245.2	(1.2)	246.4	2,151.6	(47.1)	2,198.7
Large Commercial/Industrial	184.4	5.8	178.6	2,444.3	70.6	2,373.7
Other - Retail	6.0	(0.1)	6.1	40.4	0.4	40.0
Total Retail	710.2	(3.9)	714.1	6,579.2	(63.2)	6,642.4
Wholesale - Other	36.7	0.7	36.0	332.7	(146.1)	478.8
Resale - Utilities	17.0	(0.5)	17.5	597.1	28.5	568.6
Other Operating Revenues	13.4	4.4	9.0	—	—	—
Total	$ 777.3	$ 0.7	$ 776.6	7,509.0	(180.8)	7,689.8
Weather -- Degree Days (a)						
Heating (3,306 Normal)				2,610	(834)	3,444

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

Our electric utility operating revenues increased by $0.7 million , or 0.1% , when compared to the first quarter of 2011 . The most significant factors that caused a change in revenues were:

- Unfavorable weather as compared to the prior year that decreased electric revenues by an estimated $19.3 million.
- Net pricing increases totaling $8.8 million, which primarily includes rates related to our request to review 2011 fuel costs that became effective April 29, 2011. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.
- A $4.4 million increase in other operating revenues, which includes the amortization of $6.7 million related to the DOE settlement used to offset an increase in fuel costs authorized by the PSCW. For additional information on the DOE settlement, see Factors Affecting Results, Liquidity and Capital Resources -- Nuclear Operations.

As measured by heating degree days, the first quarter of 2012 was 24.2% warmer than the same period in 2011 and 21.1% warmer than normal. The decrease in residential sales volumes in 2012 is primarily attributable to the warmer weather.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $13.7 million, or 5.1%, when compared to the first quarter of 2011. This decrease was primarily caused by a 2.4% decrease in total MWh sales as well as lower generating costs driven by a decrease in natural gas prices as compared to the first quarter of 2011.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first quarter of 2012 with the first quarter of 2011 . We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues decreased by $136.2 million , or 26.0% , and cost of gas sold decreased by $104.9 million , or 30.6% , due to the significantly warmer winter weather, which resulted in lower therm deliveries, and a decline in the commodity cost of natural gas.

	Three Months Ended March 31		
	2012	B (W)	2011
		(Millions of Dollars)	
Gas Operating Revenues	$ 388.5	$ (136.2)	$ 524.7
Cost of Gas Sold	237.5	104.9	342.4
Gross Margin	$ 151.0	$ (31.3)	$ 182.3

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first quarter of 2012 with the first quarter of 2011:

	Gross Margin			Therm Deliveries		
Gas Utility Operations	2012	B (W)	2011	2012	B (W)	2011
		(Millions of Dollars)			(Millions)	
Customer Class						
Residential	$ 97.9	$ (20.7)	$ 118.6	298.2	(92.8)	391.0
Commercial/Industrial	35.8	(9.4)	45.2	170.6	(50.8)	221.4
Interruptible	0.6	—	0.6	5.0	(1.4)	6.4
Total Retail	134.3	(30.1)	164.4	473.8	(145.0)	618.8
Transported Gas	14.7	(0.9)	15.6	324.1	60.4	263.7
Other	2.0	(0.3)	2.3	—	—	—
Total	$ 151.0	$ (31.3)	$ 182.3	797.9	(84.6)	882.5
Weather -- Degree Days (a)						
Heating (3,306 Normal)				2,610	(834)	3,444

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

Our gas margin decreased by $31.3 million , or approximately 17.2% , when compared to the first quarter of 2011 as a result of record warm winter weather. The first quarter of 2012 was the warmest winter in 122 years. As measured by heating degree days, the first quarter of 2012 was 24.2% warmer than the same period in 2011 and 21.1% warmer than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $24.5 million, or approximately 6.1%, when compared to the first quarter of 2011. This decrease, which we expect to continue through the remainder of the year, is primarily due to the one year suspension of $148 million of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case. For additional information on the 2012 rate case, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $7.3 million , or approximately 11.5% , when compared to the first quarter of 2011 primarily because of an overall increase in utility plant in service. The Glacier Hills Wind Park went in service in December 2011. We expect depreciation expense to increase in 2012 related to the in-service events of the Oak Creek Air Quality Control System (AQCS) project. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment consists primarily of our PTF units (Port Washington Generating Station Unit 1 (PWGS 1), Port Washington Generating Station Unit 2 (PWGS 2), Oak Creek expansion Unit 1 (OC 1) and OC 2). PWGS 1 and PWGS 2 were placed in service in July 2005 and May 2008, respectively. The common facilities associated with the Oak Creek expansion include the water intake system, which was placed in service in January 2009, the coal handling system, which was placed in service in November 2007, and other smaller assets. OC 1 and OC 2 were placed in service in February 2010 and January 2011, respectively.

The table below reflects a full quarter's earnings in 2012 and 2011 for PWGS 1, PWGS 2, OC 1 and the common facilities for the Oak Creek expansion. It also reflects a full quarter's earnings in 2012 and approximately two and a half months of earnings in 2011 for OC 2. This segment reflects the lease revenues on the new units as well as the depreciation expense. Operating and maintenance costs associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	Three Months Ended March 31, 2012			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$ 26.5	$ 80.3	$ 0.5	$ 107.3
Operation and Maintenance Expense	0.1	0.5	1.5	2.1
Depreciation Expense	4.9	11.7	0.2	16.8
Operating Income (Loss)	$ 21.5	$ 68.1	$ (1.2)	$ 88.4

	Three Months Ended March 31, 2011			
	Port Washington	Oak Creek Expansion	All Other	Total
	(Millions of Dollars)			
Operating Revenues	$ 26.0	$ 77.2	$ —	$ 103.2
Operation and Maintenance Expense	0.1	0.6	0.8	1.5
Depreciation Expense	4.9	12.3	0.5	17.7
Operating Income (Loss)	$ 21.0	$ 64.3	$ (1.3)	$ 84.0

CONSOLIDATED OTHER INCOME, NET

	Three Months Ended March 31		
	2012	B (W)	2011
	(Millions of Dollars)		
AFUDC - Equity	$ 14.8	$ 2.7	$ 12.1
Other, net	1.2	0.8	0.4
Other Income, net	$ 16.0	$ 3.5	$ 12.5

Other income, net increased by $3.5 million, or approximately 28.0%, when compared to the first quarter of 2011. The increase in AFUDC - Equity is primarily related to the construction of the Oak Creek AQCS project and the Rothschild biomass facility. We expect AFUDC-Equity to decrease after the Oak Creek AQCS project goes in service. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended March 31		
	2012	B (W)	2011
		(Millions of Dollars)	
Gross Interest Costs	$ 65.3	$ 4.6	$ 69.9
Less: Capitalized Interest	6.4	(0.1)	6.5
Interest Expense, net	$ 58.9	$ 4.5	$ 63.4

Our gross interest costs decreased by $4.6 million, or approximately 6.6%, when compared to the first quarter of 2011 primarily because we retired $450 million of long-term debt in April 2011. This decrease was partially offset by increased interest costs associated with the issuance of $300 million of long-term debt by Wisconsin Electric in September 2011. Our capitalized interest decreased by $0.1 million. As a result, our net interest expense decreased by $4.5 million, or 7.1%, as compared to the first quarter of 2011.

CONSOLIDATED INCOME TAX EXPENSE

For the first quarter of 2012, our effective tax rate applicable to continuing operations was 35.9% compared to 34.3% for the first quarter of 2011. For additional information, see Note H -- Income Taxes in our 2011 Annual Report on Form 10-K. We expect our 2012 annual effective tax rate to be between 35.5% and 36.5%.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following summarizes our cash flows from continuing operations during the three months ended March 31 :

	2012	2011
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$ 340.5	$ 391.0
Investing Activities	$ (130.4)	$ (144.4)
Financing Activities	$ (206.1)	$ (35.1)

Operating Activities

Cash provided by operating activities declined by $50.5 million during the first quarter of 2012 as compared to the same period in 2011. In the first quarter of 2011, we expensed approximately $37.0 million of non-cash charges associated with the amortization of certain regulatory assets and liabilities. The PSCW allowed us to suspend these amortizations in 2012. In addition, in 2011, we received approximately $45.5 million in refunds related to the DOE settlement, which were recorded as a regulatory liability. During the first quarter of 2011, we contributed $122.4 million to our qualified benefit plans. We made no such contributions to our qualified plans in the first quarter of 2012.

Investing Activities

Cash used in investing activities declined by $14.0 million during the first quarter of 2012 as compared to the same period in 2011. Our capital expenditures increased by $6.8 million during the first quarter of 2012 as compared to the same period in 2011, primarily because of increased spending on the biomass facility. During the first quarter of 2011, we received proceeds from asset sales totaling $38.3 million in connection with the sale of our interest in Edgewater Generating Unit 5, as compared to proceeds of $2.7 million during the first quarter of 2012. Finally, changes in restricted cash improved our cash from investing activities by $58.0 million. In 2011, we received

$45.5 million in proceeds from the settlement with the DOE. The proceeds were treated as restricted cash, which was recorded as cash used in investing activities. In 2012, we released $20.8 million of the proceeds through bill credits and the reimbursement of costs. The release of restricted cash was treated as cash provided by investing activities.

Financing Activities

Cash used in financing activities increased by $171.0 million during the first quarter of 2012 as compared to the same period in 2011. During the first quarter of 2011, we issued $420.0 million of long-term debt in connection with the commercial operation of OC 2. We did not issue any long-term debt during the first quarter of 2012. In addition, in January 2012, our Board of Directors approved a 15.4% increase in the quarterly common stock dividend effective with the first quarter 2012 dividend payment.

CAPITAL RESOURCES AND REQUIREMENTS

Liquidity

We anticipate meeting our capital requirements during the remainder of 2012 and beyond primarily through internally generated funds and short-term borrowings, supplemented as necessary by the issuance of intermediate or long-term debt securities, depending on market conditions and other factors.

We currently have access to the capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We currently believe that we have adequate capacity to fund our operations for the foreseeable future through our existing borrowing arrangements, access to capital markets and internally generated cash.

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas maintain bank back-up credit facilities, which provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes.

As of March 31, 2012 , we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities, and approximately $557.3 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During the first three months of 2012 , our maximum commercial paper outstanding was $669.9 million with a weighted-average interest rate of 0.27%.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes such facilities as of March 31, 2012:

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
		(Millions of Dollars)		
Wisconsin Energy	$ 450.0	$ 0.4	$ 449.6	December 2013
Wisconsin Electric	$ 500.0	$ 4.4	$ 495.6	December 2013
Wisconsin Gas	$ 300.0	$ —	$ 300.0	December 2013

The following table shows our capitalization structure as of March 31, 2012 , as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view Wisconsin Energy's 2007 Series A Junior Subordinated notes (Junior Notes):

Capitalization Structure	Actual	Adjusted
	(Millions of Dollars)	
Common Equity	$ 4,051.5	$ 4,301.5
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	4,636.6	4,386.6
Short-Term Debt	557.3	557.3
Total Capitalization	$ 9,275.8	$ 9,275.8
Total Debt	$ 5,193.9	$ 4,943.9
Ratio of Debt to Total Capitalization	56.0%	53.3%

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of March 31, 2012 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% or greater equity credit the majority of rating agencies currently attribute to the Junior Notes.

The adjusted presentation of our consolidated capitalization structure is presented as a complement to our capitalization structure presented in accordance with GAAP. Management evaluates and manages Wisconsin Energy's capitalization structure, including its total debt to total capitalization ratio, using the GAAP calculation as adjusted by the rating agency treatment of the Junior Notes. Therefore, we believe the non-GAAP adjusted presentation reflecting this treatment is useful and relevant to investors in understanding how management and the rating agencies evaluate our capitalization structure.

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amounts of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric issued commercial paper to fund the purchase of the bonds. As of March 31, 2012, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

Credit Rating Risk

Access to capital markets at a reasonable cost is determined in large part by credit quality. Any credit ratings downgrade could impact our ability to access capital markets.

Subject to other factors affecting the credit markets as a whole, we believe our current ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, security ratings reflect the views of the rating agencies only. An explanation of the significance of the ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency.

See Capital Resources and Requirements -- Credit Rating Risk in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2011 Annual Report on Form 10-K for additional information related to our credit rating risk.

Capital Requirements

Capital Expenditures: Capital requirements during the remainder of 2012 are expected to be principally for capital expenditures in our utility operations relating to our electric and gas distribution systems, our biomass facility and environmental controls at our Oak Creek generating units. Our 2012 consolidated capital expenditure estimate is approximately $740 million.

Common Stock Matters: On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. Funds for the repurchases are expected to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. Through March 31, 2012, we have acquired approximately 3.2 million shares in the open market at a cost of $100.0 million pursuant to this program.

On January 19, 2012, our Board of Directors approved a new dividend policy. Pursuant to this new policy, we will target a dividend payout ratio that trends toward 60% of earnings in the year 2014. At the same time, in accordance with that policy, our Board of Directors increased our quarterly dividend to $0.30 per share effective with the first quarter 2012 dividend payment, which would result in annual dividends of $1.20 per share.

Off-Balance Sheet Arrangements: We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit which support construction projects, commodity contracts and other payment obligations. We continue to believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note 10 -- Variable Interest Entities in the Notes to Consolidated Condensed Financial Statements in this report.

Contractual Obligations/Commercial Commitments: Our total contractual obligations and other commercial commitments were approximately $21.9 billion as of March 31, 2012 compared with $22.2 billion as of December 31, 2011. Our total contractual obligations and other commercial commitments as of March 31, 2012 decreased compared with December 31, 2011 primarily due to periodic payments related to these obligations which were greater than new commitments made in the ordinary course of business.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

The following is a discussion of certain factors that may affect our results of operations, liquidity and capital resources. The following discussion should be read together with the information under the heading "Factors Affecting Results, Liquidity and Capital Resources" in Item 7 of our 2011 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, our PTF strategy, utility rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

POWER THE FUTURE

All of the PTF units are in service and are positioned to provide a significant portion of our future generation needs. We are recovering our costs in these units through lease payments associated with PWGS 1, PWGS 2 and OC 1 that are billed from We Power to Wisconsin Electric and then recovered in Wisconsin Electric's rates as authorized by the PSCW, the Michigan Public Service Commission (MPSC) and FERC. Wisconsin Electric is recovering the lease payments associated with OC 2 as authorized by the PSCW and FERC, and has requested authorization from the MPSC in the rate case filed in July 2011. See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2011 Annual Report on Form 10-K for additional information on PTF.

UTILITY RATES AND REGULATORY MATTERS

2013 Wisconsin Rate Case: On March 23, 2012, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. Wisconsin Electric has asked the PSCW to approve a net bill increase related to non-fuel costs for its Wisconsin retail electric customers of approximately $99.3 million (3.6%) for 2013. This proposed increase reflects an offset to the revenue requirement of approximately $73.3 million related to the proceeds of a renewable energy cash grant we expect to receive under the National Defense Authorization Act (NDAA) upon completion of our biomass facility currently under construction. Wisconsin Electric's proposed plan, if approved by the PSCW, would return the proceeds from the cash grant to customers in the form of bill credits.

Absent the bill credits, the total electric rate increase requested by Wisconsin Electric is approximately $172.6 million (6.2%) for 2013. Wisconsin Electric is requesting an additional increase in electric rates of approximately $37.4 million in 2014, which would result in a 3.6% net bill increase for its Wisconsin retail electric customers. Wisconsin Electric also filed its fuel cost plan for 2013 with the PSCW as required by the Wisconsin fuel rules.

For its natural gas customers, Wisconsin Electric requested a rate decrease of approximately $1.2 million (0.2%) for 2013 with no rate adjustment for 2014. In addition, Wisconsin Electric requested rate increases of approximately $1.3 million (6.0%) for its Valley steam utility customers in 2013 and 2014, and approximately $1.0 million (7.0%) and $1.0 million (6.0%) for its Milwaukee County steam utility customers in 2013 and 2014, respectively.

Wisconsin Gas has asked the PSCW to approve a rate decrease for its natural gas customers of approximately $15.9 million (2.3%) for 2013, with no rate adjustment for 2014.

2012 Wisconsin Rate Case: On May 26, 2011, Wisconsin Electric and Wisconsin Gas filed an application with the PSCW to initiate rate proceedings. In lieu of a traditional rate proceeding, we requested an alternative approach, which results in no increase in 2012 base rates for our customers. In order for us to proceed under this alternative approach, Wisconsin Electric and Wisconsin Gas requested that the PSCW issue an order that:

- Authorizes Wisconsin Electric to suspend the amortization of $148 million of regulatory costs during 2012, with amortization to begin again in 2013.
- Authorizes $148 million of carrying costs and depreciation on previously authorized air quality and renewable energy projects, effective January 1, 2012.
- Authorizes the refund of $26 million of net proceeds from Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE.
- Authorizes Wisconsin Electric to reopen the rate proceeding in 2012 to address, for rates effective in 2013, all issues set aside during 2012, including the determination of the final approved construction costs for the Oak Creek expansion (see 2013 Wisconsin Rate Case above).
- Schedules a proceeding to establish a 2012 fuel cost plan.

We received a final written order from the PSCW on November 3, 2011. For information related to the proceeding to establish a 2012 fuel cost plan, see 2012 Fuel Recovery Request below.

2012 Michigan Rate Case: On July 5, 2011, Wisconsin Electric filed a $17.5 million rate increase request with the MPSC, primarily to recover the costs of environmental upgrades and OC 2. Michigan law allows utilities, upon the satisfaction of certain conditions, to self-implement a rate increase request, subject to refund with interest. Therefore, in January 2012, we implemented a $5.7 million interim electric base rate increase. This increase is offset by a refund of $2.7 million of net proceeds from Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE, resulting in a net $3.0 million rate increase. In addition, approximately $2.0 million of renewable costs were included in our Michigan fuel recovery rate effective January 1, 2012. Therefore, the total self-implementation was $7.7 million. A final decision from the MPSC is expected in July 2012.

2012 Fuel Recovery Request: On August 3, 2011, Wisconsin Electric filed a $50 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The primary reasons for the increase are projected higher coal, coal transportation and purchased power costs. This filing was made under the new Wisconsin fuel rules which require annual fuel cost filings. On January 5, 2012, the PSCW issued an order which provided for an increase in fuel costs of approximately $26 million, offset by approximately $26 million from the settlement with the DOE regarding the storage of spent nuclear fuel, resulting in no change in customer bills.

2010 Wisconsin Rate Case: As part of its final decision in the 2010 rate case, the PSCW authorized Wisconsin Electric to reopen the docket in 2010 to review updated 2011 fuel costs. On September 3, 2010, Wisconsin Electric filed an application with the PSCW to reopen the docket to review updated 2011 fuel costs and to set rates for 2011 that reflect those costs. Wisconsin Electric requested an increase in 2011 Wisconsin retail electric rates of $38.4 million, or 1.4%, related to the increase in 2011 monitored fuel costs as compared to the level of monitored fuel costs then embedded in rates. In December 2010, Wisconsin Electric reduced its request by approximately $5.2 million. Adjustments by the PSCW reduced the request by an additional $7.8 million. The PSCW issued its final decision, which increased annual Wisconsin retail rates by $25.4 million effective April 29, 2011. The net increase was being driven primarily by an increase in the delivered cost of coal.

2010 Fuel Recovery Request: In February 2010, Wisconsin Electric filed a $60.5 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The increase in fuel and purchased power costs was driven primarily by increases in the price of natural gas compared to the forecasted prices included in the 2010 PSCW rate case order, changes in the timing of plant outages and increased MISO costs. Effective March 25, 2010, the PSCW approved an annual increase of $60.5 million in Wisconsin retail electric rates on an interim basis. On April 28, 2011, the PSCW approved the final increase with no changes.

Renewable Energy Portfolio: We are constructing a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood waste and wood shavings will be used to produce approximately 50 MW of renewable electricity and will also support Domtar's sustainable papermaking operations. Construction commenced on June 27, 2011. We currently expect to invest between $245 million and $255 million, excluding AFUDC, in the plant and we expect the plant to be completed during the fall of 2013.

Pursuant to the NDAA, which was passed in December 2011, utilities are now able to elect to receive a cash grant for renewable energy projects without the effect of normalization for income tax purposes. As a result of the NDAA, we currently anticipate pursuing a cash grant relating to the biomass facility.

Oak Creek Air Quality Control System: In July 2008, we received approval from the PSCW granting Wisconsin Electric authority to construct wet flue gas desulfurization and selective catalytic reduction facilities at Oak Creek Power Plant units 5-8. Construction of these emission controls began in late July 2008. On March 3, 2012, the wet flue gas desulfurization and selective catalytic reduction equipment for units 5 and 6 was placed into commercial operation. We expect the equipment for units 7 and 8 to be completed by the end of summer 2012. We currently expect the cost of completing this project to be approximately $750 million ($900 million including AFUDC).

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 of our 2011 Annual Report on Form 10-K for additional information regarding our utility rates and other regulatory matters.

ENVIRONMENTAL MATTERS

Air Quality

Mercury and Other Hazardous Air Pollutants: On December 16, 2011, the EPA issued the final utility MACT rule (referred to as the Mercury and Air Toxics Standards (MATS) rule), which imposes stringent limitations on numerous hazardous air pollutants, including mercury, from coal and oil-fired electric generating units. While we are continuing to evaluate the impact of the rule on the operation of our existing coal-fired generation facilities, as well as alternatives for complying with the rule, we currently estimate our capital cost to comply with this rule will be approximately $16 million to $25 million. Based upon our review, the VAPP and Presque Isle Power Plant may require modifications. We believe that our clean air strategy, including the environmental upgrades that have already been constructed and that are currently under construction at our other plants, positions those plants well to meet the rule's requirements.

Cross-State Air Pollution Rule: On August 8, 2011, the EPA issued a final rule, the Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule was proposed in 2010 to replace the Clean Air Interstate Rule (CAIR), which had been remanded to the EPA in 2008. The stated purpose of the CSAPR is to limit the interstate transport of emissions of Nitrogen Oxide (NO_x) and SO_2 that contribute to fine particulate matter and ozone non-attainment in downwind states through a proposed allocation scheme. On February 7, 2012, the EPA issued final technical revisions to the rule and issued a draft final rule which together delay the implementation date for certain penalty provisions that could potentially impact the Presque Isle Power Plant and increase the number of allowances issued to the states of Michigan and Wisconsin. Even with these proposed revisions, however, the Presque Isle Power Plant may not have been allocated sufficient allowances to meet its obligations to operate and provide stability to the transmission system in the Upper Peninsula of Michigan. This situation could then put the plant at risk for certain penalties under the rule.

The rule was scheduled to become effective January 1, 2012. However, we and a number of other parties sought judicial review of the rule, and on December 30, 2011, the U.S. Court of Appeals for the District of Columbia granted a motion to stay CSAPR pending judicial review of the rule. While the CSAPR is stayed, the CAIR will remain in effect. We are unable to predict the outcome of this review at this time.

Climate Change: Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. The regulation of greenhouse gas emissions through legislation and regulation has been, and continues to be, a focus of the President and his administration. Although legislation that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards and/or energy efficiency standards failed to pass in the U.S. Congress, we expect such legislation to be considered in the future. Any mandatory restrictions on our Carbon Dioxide (CO_2) emissions that may be adopted by Congress or Wisconsin's or Michigan's legislature could result in significant compliance costs that could affect future results of operations, cash flows and financial condition.

On March 27, 2012, the EPA, using its existing authority under the Clean Air Act (CAA), proposed new source performance standards pertaining to greenhouse gas emissions from certain new power plants, including coal-fueled plants, based on the performance of combined cycle natural gas-fueled generating plants. We believe this rule effectively prohibits new conventional coal-fueled power plants.

We expect the EPA to attempt to address performance standards for reconstructed and modified generating units in a future rule. Any such rule may impact our ability to do maintenance or modify our existing facilities. Depending on the extent of rate recovery and other factors, these anticipated future rules could have a material adverse impact on our financial condition. For additional information, see the caption "We may face significant costs to comply with the regulation of greenhouse gas emissions." under Item 1A Risk Factors in our 2011 Annual Report on Form 10-K.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2011 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

LEGAL MATTERS

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. The complaint alleged that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of ERISA and were owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant.

In November 2011, we entered into a settlement agreement with the plaintiffs for $45.0 million, and the court promptly issued an order preliminarily approving the settlement. As part of the settlement agreement, we agreed to class certification for all similarly situated plaintiffs. The resolution of this matter resulted in a cost of less than $0.04 per share for 2011 after considering insurance and reserves established in the prior year. The court approved the settlement on April 3, 2012 and issued its written order on April 20, 2012. The plaintiffs have 30 days from the date of the written order to appeal this decision.

We do not anticipate further charges as a result of the settlement, other than certain process-related costs we expect to incur to implement the settlement.

NUCLEAR OPERATIONS

Used Nuclear Fuel Storage and Disposal: The Nuclear Waste Policy Act established the Nuclear Waste Fund, which is composed of payments made by the generators and owners of nuclear plants. Wisconsin Electric owned Point Beach through September 2007 and placed approximately $215.2 million into this fund. Effective January 31, 1998, the DOE failed to meet its contractual obligation to begin removing used fuel from Point Beach. Wisconsin Electric filed a complaint in November 2000 against the DOE in the Court of Federal Claims for failure to begin performance. In December 2009, the Court ruled in favor of Wisconsin Electric, granting us more than $50 million in damages. In February 2010, the DOE filed an appeal. We negotiated a settlement with the DOE for $45.5 million, which we received in the first quarter of 2011. This amount, net of costs incurred, is being returned to customers as part of the PSCW's approval of our 2012 fuel recovery request and the MPSC's approval of our interim order for the 2012 Michigan rate case.

OTHER MATTERS

Oak Creek Expansion Fuel Flexibility Project: The Oak Creek expansion units were designed and permitted to use bituminous coal from the Eastern United States rather than sub-bituminous coal. Market forces have resulted in a significant price differential between bituminous and sub-bituminous coals. We have applied for a new air permit from the WDNR to modify the Oak Creek expansion units for potential future use of sub-bituminous coal. Upon receiving an air permit, we intend to begin testing sub-bituminous coal in various combinations with bituminous coal to identify any equipment limitations that should be considered prior to filing with the PSCW for a Certificate of Authority to make the fuel flexibility modifications permanent.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes related to market risk from the disclosures presented in our Annual Report on Form 10-K for the year ended December 31, 2011. For information concerning market risk exposures at Wisconsin Energy Corporation, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks, in Part II of our 2011 Annual Report on Form 10-K, as well as Note 6 -- Fair Value Measurements and Note 7 -- Derivative Instruments in the Notes to Consolidated Condensed Financial Statements in this report.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures: Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting: There has not been any change in our internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fiscal quarter to which this report relates that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2011 Annual Report on Form 10-K.

In addition to those legal proceedings discussed in our reports to the SEC, we are currently, and from time to time, subject to claims and suits arising in the ordinary course of business. Although the results of these legal proceedings cannot be predicted with certainty, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material effect on our financial statements.

ENVIRONMENTAL MATTERS

Bluff Collapse: On October 31, 2011, a portion of the bluff at our Oak Creek Power Plant collapsed. The affected area, located south of the AQCS that is currently under construction, was a former ravine that had been filled with coal ash prior to the advent of landfill regulations.

A mixture of soil, coal ash and water, along with several trailers, vehicles and other construction materials from the AQCS construction site, slid down the bluff to the shoreline area. Some of these materials fell into Lake Michigan.

We worked with the U.S. Coast Guard, WDNR and EPA to coordinate an incident action plan for completing the recovery and clean-up efforts. Ash and soil materials have been removed from the area, and construction equipment and related materials have been removed from Lake Michigan. The clean-up work has been completed, and the bluff was stabilized for the winter. We expect that permanent bluff reconstruction and stabilization work will commence during the second quarter of 2012.

We consulted with nearby water utilities and they indicated that there were no impacts to public drinking water supplies. In November 2011, the WDNR conducted a survey of Lake Michigan's lakebed. The survey did not locate any fly ash or construction materials on the lakebed immediately east and south of the Oak Creek site. Both water quality and sediment sampling have not indicated a serious risk of harm to human health or the environment.

The WDNR issued a Notice of Violation (NOV) along with its investigative findings on March 1, 2012, and an enforcement conference was held with representatives of Wisconsin Electric on March 7, 2012. The NOV involves the north surface water detention basin and a related permit condition. Ash deposits were removed from beneath the north detention basin during construction, which we believe was consistent with the permit condition requiring installation of a liner only if the basin was placed over a "waste area." Therefore, we do not believe a liner was required. We have also provided answers to follow-up questions provided by the WDNR at the enforcement conference. The WDNR or other regulatory agency may seek fines or penalties from us as a result of this incident.

In addition, on November 8, 2011, the Sierra Club provided a Notice of Intent to file a citizens suit under the CAA and Resource Conservation and Recovery Act for alleged violations related to this incident. We have responded that we do not believe there is any basis for a citizen suit. To date, Sierra Club has not indicated whether they intend to file suit.

UTILITY RATES AND REGULATORY MATTERS

See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Part I of this report for information concerning rate matters in the jurisdictions where Wisconsin Electric and Wisconsin Gas do business.

OTHER MATTERS

See Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Item 2 of this report for information regarding a lawsuit filed against the Plan.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors presented in our Annual Report on Form 10-K for the year ended December 31, 2011. See Item 1A. Risk Factors in our 2011 Annual Report on Form 10-K for a discussion of certain risk factors applicable to us.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth information regarding the purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three months ended March 31, 2012:

ISSUER PURCHASES OF EQUITY SECURITIES

2012	Total Number of Shares Purchased (a)	Average Price Paid per Share		Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (b)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs	
					(Millions of Dollars)	
January 1 - January 31	9,217	$	34.64	—	$	200.0
February 1 - February 29	—	$	—	—	$	200.0
March 1 - March 31	2,575	$	35.11	—	$	200.0
Total	11,792	$	34.74	—		

(a) All shares reported during the quarter were surrendered by employees to satisfy tax withholding obligations upon vesting of restricted stock.

(b) On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to $300 million of our common stock through December 31, 2013.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

ITEM 5. OTHER INFORMATION

Director Frederick P. Stratton, Jr. did not stand for re-election at the 2012 Annual Meeting of Stockholders of Wisconsin Energy held on May 3, 2012, at which time his term expired. Director Stratton has served on the Wisconsin Energy Board of Directors since 1987, the Wisconsin Electric Board of Directors since 1986 and the Wisconsin Gas Board of Directors since 2000. In consideration of his exemplary service and contributions to these Boards of Directors, on May 1, 2012, the Compensation Committee accelerated the vesting of all unvested shares of restricted stock awarded to Director Stratton, consisting of approximately 8,212 shares, effective May 3, 2012.

ITEM 6. EXHIBITS

Exhibit No.

10 Material Contracts

10.1 Terms of Employment for Susan H. Martin.

31 Rule 13a-14(a) / 15d-14(a) Certifications

31.1 Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32 Section 1350 Certifications

32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101 Interactive Data File

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

WISCONSIN ENERGY CORPORATION
(Registrant)

		/s/STEPHEN P. DICKSON
Date:	May 3, 2012	Stephen P. Dickson, Vice President and Controller, Principal Accounting Officer and duly authorized officer

Exhibit 10.1

NAME	Susan Martin	
POSITION	General Counsel & Corp. Secretary	
Base Salary	$	405,000
2012 STPP AWARD*		
Target Award (70%)	$	283,500
2013 STOCK OPTIONS**		
Theoretical Value	$	91,125
2013 RESTRICTED STOCK**		
Market Value	$	91,125
2013 PERFORMANCE UNITS**		
Market Value	$	425,250
TOTAL VALUE OF PAY PROGRAM*	**$**	**1,296,000**

* Reflects post-promotion value

** Estimated value: Reflects post-promotion award based on today's market

Note: Ms. Martin is entitled to participate in the company's pension plan and other retirement plans. In addition, Ms. Martin is eligible for an executive financial planning benefit, executive life insurance and executive annual physical benefit on a basis commensurate with other Executive Vice Presidents of the company.

Exhibit 31.1

Certification Pursuant to
Rule 13a-14(a) or 15d-14(a),
as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Gale E. Klappa, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Wisconsin Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/GALE E. KLAPPA
Gale E. Klappa
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

Certification Pursuant to
Rule 13a-14(a) or 15d-14(a),
as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Frederick D. Kuester, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Wisconsin Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 3, 2012

/s/FREDERICK D. KUESTER
Frederick D. Kuester
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

XCEL ENERGY INC (XEL)

10-Q

Quarterly report pursuant to sections 13 or 15(d)
Filed on 04/27/2012
Filed Period 03/31/2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2012
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 1-3034

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota (State or other jurisdiction of incorporation or organization)	**41-0448030** (I.R.S. Employer Identification No.)
414 Nicollet Mall Minneapolis, Minnesota (Address of principal executive offices)	**55401** (Zip Code)

(612) 330-5500
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒Yes ☐No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒Yes ☐No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐Yes ☒No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at April 19, 2012
Common Stock, $2.50 par value	486,943,183 shares

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This Form 10-Q is filed by Xcel Energy Inc. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); and Southwestern Public Service Company (SPS). Xcel Energy Inc. and its consolidated subsidiaries are also referred to herein as Xcel Energy. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. Additional information on the wholly owned subsidiaries is available on various filings with the Securities and Exchange Commission (SEC).

PART I — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)
(amounts in thousands, except per share data)

	Three Months Ended March 31	
	2012	**2011**
Operating revenues		
Electric	$ 1,936,782	$ 2,029,972
Natural gas	621,035	765,349
Other	20,262	21,219
Total operating revenues	2,578,079	2,816,540
Operating expenses		
Electric fuel and purchased power	863,980	931,828
Cost of natural gas sold and transported	417,946	543,376
Cost of sales — other	7,304	8,055
Operating and maintenance expenses	510,684	510,027
Conservation and demand side management program expenses	63,707	75,298
Depreciation and amortization	228,672	224,723
Taxes (other than income taxes)	105,624	96,570
Total operating expenses	2,197,917	2,389,877
Operating income	380,162	426,663
Other income, net	3,737	4,766
Equity earnings of unconsolidated subsidiaries	7,158	7,713
Allowance for funds used during construction — equity	13,450	13,244
Interest charges and financing costs		
Interest charges — includes other financing costs of $6,080 and $5,260, respectively	151,830	144,354
Allowance for funds used during construction — debt	(6,607)	(7,436)
Total interest charges and financing costs	145,223	136,918
Income from continuing operations before income taxes	259,284	315,468
Income taxes	75,515	112,001
Income from continuing operations	183,769	203,467
Income from discontinued operations, net of tax	124	102
Net income	183,893	203,569
Dividend requirements on preferred stock	-	1,060
Earnings available to common shareholders	$ 183,893	$ 202,509
Weighted average common shares outstanding:		
Basic	487,360	483,641
Diluted	487,995	484,301
Earnings per average common share:		
Basic	$ 0.38	$ 0.42
Diluted	0.38	0.42
Cash dividends declared per common share	$ 0.26	$ 0.25

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended March 31	
	2012	2011
Net income	$ 183,893	$ 203,569
Other comprehensive income		
Pension and retiree medical benefits:		
Amortization of losses included in net periodic benefit cost, net of tax of $622 and $551, respectively	895	794
Derivative instruments:		
Net fair value increase, net of tax of $16,491 and $145, respectively	25,392	244
Reclassification of losses to net income, net of tax of $156 and $147, respectively	181	158
	25,573	402
Marketable securities:		
Net fair value increase, net of tax of $36 and $34, respectively	52	50
Other comprehensive income	26,520	1,246
Comprehensive income	$ 210,413	$ 204,815

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in thousands)

	Three Months Ended March 31 2012	2011
Operating activities		
Net income	$ 183,893	$ 203,569
Remove income from discontinued operations	(124)	(102)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	233,097	229,217
Conservation and demand side management program amortization	1,882	3,024
Nuclear fuel amortization	26,000	25,551
Deferred income taxes	167,426	114,852
Amortization of investment tax credits	(1,552)	(1,580)
Allowance for equity funds used during construction	(13,450)	(13,244)
Equity earnings of unconsolidated subsidiaries	(7,158)	(7,713)
Dividends from unconsolidated subsidiaries	8,028	8,454
Share-based compensation expense	3,883	9,895
Net derivative losses	7,133	14,495
Changes in operating assets and liabilities:		
Accounts receivable	(52,643)	(46,947)
Accrued unbilled revenues	197,330	157,996
Inventories	143,873	118,595
Other current assets	(71,547)	43,551
Accounts payable	(202,649)	(72,424)
Net regulatory assets and liabilities	61,872	17,853
Other current liabilities	17,711	5,491
Pension and other employee benefit obligations	(180,030)	(134,004)
Change in other noncurrent assets	(38,806)	10,520
Change in other noncurrent liabilities	(6,686)	(27,606)
Net cash provided by operating activities	477,483	659,443
Investing activities		
Utility capital/construction expenditures	(497,218)	(540,339)
Allowance for equity funds used during construction	13,450	13,244
Merricourt deposit	-	(90,833)
Purchase of investments in external decommissioning fund	(213,618)	(699,156)
Proceeds from the sale of investments in external decommissioning fund	213,618	699,156
Investment in WYCO Development LLC	(172)	(901)
Change in restricted cash	86,232	26
Other, net	(1,304)	(5,545)
Net cash used in investing activities	(399,012)	(624,348)
Financing activities		
Proceeds from short-term borrowings, net	120,000	65,100
Proceeds from issuance of long-term debt	745	-
Repayments of long-term debt, including reacquisition premiums	(758)	(551)
Proceeds from issuance of common stock	1,598	1,878
Repurchase of common stock	(18,529)	-
Purchase of common stock for settlement of equity awards	(23,307)	-
Dividends paid	(119,162)	(115,621)
Net cash used in financing activities	(39,413)	(49,194)
Net change in cash and cash equivalents	39,058	(14,099)
Cash and cash equivalents at beginning of period	60,684	108,437
Cash and cash equivalents at end of period	$ 99,742	$ 94,338
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (156,275)	$ (150,473)
Cash (paid) received for income taxes, net	(1,173)	59,051
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$ 224,316	$ 116,145
Issuance of common stock for reinvested dividends and 401(k) plans	18,815	20,419

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(amounts in thousands, except share and per share data)

	March 31, 2012	Dec. 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 99,742	$ 60,684
Restricted cash	9,055	95,287
Accounts receivable, net	718,145	753,120
Accrued unbilled revenues	491,410	688,740
Inventories	474,359	618,232
Regulatory assets	333,053	402,235
Derivative instruments	61,971	64,340
Deferred income taxes	162,353	178,446
Prepayments and other	192,746	121,480
Total current assets	2,542,834	2,982,564
Property, plant and equipment, net	22,672,686	22,353,367
Other assets		
Nuclear decommissioning fund and other investments	1,537,490	1,463,515
Regulatory assets	2,361,648	2,389,008
Derivative instruments	146,438	152,887
Other	192,157	155,926
Total other assets	4,237,733	4,161,336
Total assets	$ 29,453,253	$ 29,497,267
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 1,309,681	$ 1,059,922
Short-term debt	339,000	219,000
Accounts payable	786,187	902,078
Regulatory liabilities	220,526	275,095
Taxes accrued	359,064	289,713
Accrued interest	161,930	177,111
Dividends payable	126,601	126,487
Derivative instruments	56,132	157,414
Other	348,921	381,819
Total current liabilities	3,708,042	3,588,639
Deferred credits and other liabilities		
Deferred income taxes	4,212,924	4,020,377
Deferred investment tax credits	85,819	86,743
Regulatory liabilities	1,107,818	1,101,534
Asset retirement obligations	1,662,175	1,651,793
Derivative instruments	260,152	263,906
Customer advances	247,224	248,345
Pension and employee benefit obligations	813,792	1,001,906
Other	219,273	203,313
Total deferred credits and other liabilities	8,609,177	8,577,917
Commitments and contingencies		
Capitalization		
Long-term debt	8,598,363	8,848,513
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 486,935,997 and 486,493,933 shares outstanding at March 31, 2012 and Dec. 31, 2011, respectively	1,217,339	1,216,234
Additional paid in capital	5,298,572	5,327,443
Retained earnings	2,089,275	2,032,556
Accumulated other comprehensive loss	(67,515)	(94,035)
Total common stockholders' equity	8,537,671	8,482,198
Total liabilities and equity	$ 29,453,253	$ 29,497,267

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended March 31, 2012 and 2011						
Balance at Dec. 31, 2010	482,334	$ 1,205,834	$ 5,229,075	$ 1,701,703	$ (53,093)	$ 8,083,519
Comprehensive income:						
Net income				203,569		203,569
Other comprehensive income					1,246	1,246
Comprehensive income						204,815
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(122,826)		(122,826)
Issuances of common stock	1,831	4,577	1,652			6,229
Share-based compensation			10,806			10,806
Balance at March 31, 2011	484,165	$ 1,210,411	$ 5,241,533	$ 1,781,386	$ (51,847)	$ 8,181,483
Balance at Dec. 31, 2011	486,494	$ 1,216,234	$ 5,327,443	$ 2,032,556	$ (94,035)	$ 8,482,198
Comprehensive income:						
Net income				183,893		183,893
Other comprehensive income					26,520	26,520
Comprehensive income						210,413
Dividends declared:						
Common stock				(127,174)		(127,174)
Issuances of common stock	1,142	2,855	2,288			5,143
Repurchase of common stock	(700)	(1,750)	(16,779)			(18,529)
Purchase of common stock for settlement of equity awards			(23,307)			(23,307)
Share-based compensation			8,927			8,927
Balance at March 31, 2012	486,936	$ 1,217,339	$ 5,298,572	$ 2,089,275	$ (67,515)	$ 8,537,671

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of March 31, 2012 and Dec. 31, 2011 and the results of its operations, cash flows and changes in stockholders' equity for the three months ended March 31, 2012 and 2011. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2012 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2011 balance sheet information has been derived from the audited 2011 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011. These notes to the consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto, included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011, filed with the SEC on Feb. 24, 2012. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the consolidated financial statements in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

Fair Value Measurement — In May 2011, the Financial Accounting Standards Board (FASB) issued *Fair Value Measurement (Topic 820) — Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (Accounting Standards Update (ASU) No. 2011-04)*, which provides clarifications regarding existing fair value measurement principles and disclosure requirements, and also specific new guidance for items such as measurement of instruments classified within stockholders' equity. These requirements were effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy implemented the accounting and disclosure guidance effective Jan. 1, 2012, and the implementation did not have a material impact on its consolidated financial statements. For required fair value measurement disclosures, see Note 8.

Comprehensive Income — In June 2011, the FASB issued *Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05)*, which requires the presentation of the components of net income, the components of other comprehensive income (OCI) and total comprehensive income in either a single continuous financial statement of comprehensive income or in two separate, but consecutive financial statements of net income and comprehensive income. These updates do not affect the items reported in OCI or the guidance for reclassifying such items to net income. These requirements were effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy implemented the financial statement presentation guidance effective Jan. 1, 2012.

Recently Issued

Balance Sheet Offsetting — In December 2011, the FASB issued *Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11)*, which requires disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity's financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. These disclosure requirements do not affect the presentation of amounts in the consolidated balance sheets, and are effective for annual reporting periods beginning on or after Jan. 1, 2013, and interim periods within those periods. Xcel Energy does not expect the implementation of this disclosure guidance to have a material impact on its consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	March 31, 2012	Dec. 31, 2011
Accounts receivable, net		
Accounts receivable	$ 776,140	$ 811,685
Less allowance for bad debts	(57,995)	(58,565)
	$ 718,145	$ 753,120
Inventories		
Materials and supplies	$ 207,729	$ 202,699
Fuel	176,874	236,023
Natural gas	89,756	179,510
	$ 474,359	$ 618,232
Property, plant and equipment, net		
Electric plant	$ 27,393,092	$ 27,254,541
Natural gas plant	3,700,424	3,676,754
Common and other property	1,484,878	1,546,643
Plant to be retired (a)	115,401	151,184
Construction work in progress	1,315,390	1,085,245
Total property, plant and equipment	34,009,185	33,714,367
Less accumulated depreciation	(11,731,341)	(11,658,351)
Nuclear fuel	2,062,790	1,939,299
Less accumulated amortization	(1,667,948)	(1,641,948)
	$ 22,672,686	$ 22,353,367

(a) In 2010, in response to the Clean Air Clean Jobs Act (CACJA), the Colorado Public Utilities Commission (CPUC) approved the early retirement of Cherokee Units 1, 2 and 3, Arapahoe Unit 3 and Valmont Unit 5 between 2011 and 2017. In 2011, Cherokee Unit 2 was taken out of service. Amounts are presented net of accumulated depreciation.

4. Income Taxes

Except to the extent noted below, the circumstances set forth in Note 6 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 appropriately represent, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2007 federal income tax return expired in September 2011. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expires in September 2012.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of March 31, 2012, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2006
Minnesota	2007
Texas	2007
Wisconsin	2007

As of March 31, 2012, there were no state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual effective tax rate (ETR). In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefits is as follows:

(Millions of Dollars)	March 31, 2012	Dec. 31, 2011
Unrecognized tax benefit — Permanent tax positions	$ 4.4	$ 4.3
Unrecognized tax benefit — Temporary tax positions	29.5	30.4
Unrecognized tax benefit balance	$ 33.9	$ 34.7

The unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating loss (NOL) and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	March 31, 2012	Dec. 31, 2011
NOL and tax credit carryforwards	$ (32.8)	$ (33.6)

The decrease in the unrecognized tax benefit balance of $0.8 million from Dec. 31, 2011 to March 31, 2012 was due to adjustments for prior years' activity. Xcel Energy's amount of unrecognized tax benefits could change in the next 12 months as the Internal Revenue Service and state audits resume. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at March 31, 2012 and Dec. 31, 2011 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2012 or Dec. 31, 2011.

Federal Tax Loss Carryback Claims — Xcel Energy completed an analysis in the first quarter of 2012 on the eligibility of certain expenses that qualified for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a discrete tax benefit of approximately $15 million.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 12 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — Minnesota Public Utilities Commission (MPUC)

NSP-Minnesota – Minnesota Electric Rate Case — In November 2010, NSP-Minnesota filed a request with the MPUC to increase electric rates in Minnesota for 2011 by approximately $150 million, or an increase of 5.62 percent, and an additional increase of $48.3 million, or 1.81 percent, in 2012. The rate filing was based on a 2011 forecast test year, a requested return on equity (ROE) of 11.25 percent, an electric rate base of $5.6 billion and an equity ratio of 52.56 percent. The MPUC approved an interim rate increase of $123 million, subject to refund, effective Jan. 2, 2011. In August 2011, NSP-Minnesota submitted supplemental testimony, revising its requested rate increase to approximately $122 million for 2011 and an additional increase of approximately $29 million in 2012.

In November 2011, NSP-Minnesota reached a settlement agreement with various parties, which resolved all financial issues and several rate design issues. The settlement agreement includes:

- A rate increase of approximately $58 million in 2011 and an incremental rate increase of $14.8 million in 2012 based on an ROE of 10.37 percent and an equity ratio of 52.56 percent.
- A reduction to depreciation expense and NSP-Minnesota's rate request by $30 million.
- The ability for NSP-Minnesota to seek deferred accounting for incremental property tax increases associated with electric and natural gas businesses in 2012.
- The stipulation that NSP-Minnesota will not file an electric rate case prior to Nov. 1, 2012, provided that both the settlement agreement and the property tax filing are approved by the MPUC.

In February 2012, NSP-Minnesota filed to reduce the interim rate request to $72.8 million to align with the settlement agreement. On March 29, 2012, the MPUC approved the settlement and a written order is pending. As of March 31, 2012 and Dec. 31, 2011, NSP-Minnesota recorded a provision for revenue subject to refund of approximately $78 million and $67 million, respectively, to align with the settlement agreement.

NSP-Minnesota – Minnesota Property Tax Deferral Request — As part of the settlement agreement in the Minnesota electric rate case, the settling parties acknowledged that NSP-Minnesota would be filing a petition seeking deferred accounting for 2012 property tax expense in excess of the level approved in the rate case. The settling parties waived any right to object to the petition, but reserved the right to review and comment on the petition. In December 2011, NSP-Minnesota filed the petition to request deferral of approximately $28 million of incremental 2012 property taxes that will not be recovered in base rates. The estimate of 2012 incremental property taxes has been subsequently revised to approximately $24 million.

In April 2012, the Minnesota Department of Commerce (DOC) filed comments on the petition. The DOC concluded that NSP-Minnesota had not made a reasonable case for deferred accounting and recommended that the MPUC deny NSP-Minnesota's request to defer incremental 2012 property taxes and also opposed the proposed rider mechanism. The Xcel Large Industrials and the Minnesota Chamber of Commerce filed comments in support of the deferred accounting treatment as preferable to a rider mechanism, with the understanding that all costs will be reviewed in NSP-Minnesota's next rate case. Until the MPUC rules on the issue, NSP-Minnesota will continue to expense the incremental property taxes. An MPUC decision is expected in the second quarter of 2012.

Recently Concluded Regulatory Proceedings — North Dakota Public Service Commission (NDPSC)

NSP-Minnesota – North Dakota Electric Rate Case — In December 2010, NSP-Minnesota filed a request with the NDPSC to increase 2011 electric rates in North Dakota by approximately $19.8 million, or an increase of 12 percent, and a step increase of $4.2 million, or 2.6 percent, in 2012. The rate filing was based on a 2011 forecast test year and included a requested ROE of 11.25 percent, an electric rate base of approximately $328 million and an equity ratio of 52.56 percent. The NDPSC approved an interim rate increase of approximately $17.4 million, subject to refund, effective Feb. 18, 2011.

In May 2011, NSP-Minnesota revised its rate request to approximately $18.0 million, or an increase of 11 percent, for 2011 and $2.4 million, or 1.4 percent, for the additional step increase in 2012.

In September 2011, NSP-Minnesota reached a settlement with the NDPSC Advocacy Staff, which provided for a rate increase of $13.7 million in 2011 and an additional step increase of $2.0 million in 2012, based on a 10.4 percent ROE and black box settlement for all other issues. To address 2012 sales coming in below forecast revenue projections, the settlement includes a true-up to 2012 non-fuel revenues plus the settlement rate increase. In February 2012, the NDPSC approved the settlement agreement.

Pending Regulatory Proceedings — South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota – South Dakota Electric Rate Case — In June 2011, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $14.6 million annually, effective in 2012. The proposed increase included $0.7 million in revenues currently recovered through automatic recovery mechanisms. The request is based on a 2010 historic test year adjusted for known and measurable changes, a requested ROE of 11 percent, a rate base of $323.4 million and an equity ratio of 52.48 percent. NSP-Minnesota also requested approval of a nuclear cost recovery rider to recover the actual investment cost of the Monticello nuclear plant life cycle management and extended power uprate project that is not reflected in the test year. On Jan. 2, 2012, interim rates of $12.7 million were implemented.

In April 2012, the SDPUC Staff filed their direct testimony, which recommended an ROE of approximately 9 percent (ranging from 8.5 percent to 9.5 percent) and a lower cost of debt than the request (6.02 percent compared to the original request of 6.13 percent). The Staff also recommended disallowance of the Nobles wind project costs unless the SDPUC determines there is energy value in which case the Staff's recommendation would be to disallow a portion of the costs. NSP-Minnesota's rebuttal testimony is due by April 27, 2012 and a final SDPUC decision is expected in the summer of 2012.

PSCo

Recently Concluded Regulatory Proceedings — CPUC

PSCo 2011 Electric Rate Case — In November 2011, PSCo filed a request with the CPUC to increase Colorado retail electric rates by $141.9 million. The request was based on a 2012 forecast test year, a 10.75 percent ROE, an electric rate base of $5.4 billion and an equity ratio of 56 percent.

On April 26, 2012, the CPUC approved a comprehensive multi-year settlement agreement, which covers 2012 through 2014. Key terms of the agreement include the following:

- PSCo will implement an annual electric rate increase of $73 million in 2012. The rate increase will be effective on May 1, 2012, subject to refund. In addition, PSCo will implement incremental electric rate increases of $16 million on Jan. 1, 2013 and $25 million on Jan. 1, 2014. These rate increases are net of the shift of the costs from the purchased capacity cost adjustment and the transmission cost adjustment clauses to base rates.
- The settlement reflects an authorized ROE of 10 percent and an equity ratio of 56 percent.
- PSCo will forego the opportunity allowed under the CACJA to seek additional rate mechanisms to recover approved CACJA plan costs through 2014. PSCo will instead recover the carrying costs of CACJA related expenditures through the recording of allowance for funds used during construction.
- For 2012 through 2014, incremental property taxes in excess of $76.7 million (2010-2011 historic test year property taxes) will be deferred over a three-year period with the amortization effective the first year after the deferral. To the extent that PSCo is successful in gaining the manufacturer's sales tax refund as a result of the sales tax lawsuit currently pending in the Colorado Supreme Court, PSCo shall credit such refunds first against legal fees incurred to obtain the refund and then against the deferred property tax balances outstanding at the end of the 2014.
- The rates that take effect include no incremental recovery of deferred costs associated with the expiration of the Black Hills contract. However, the jurisdictional allocator used to determine the increase in base rates and for all rider calculations will reflect the expiration of the Black Hills contract as of Dec. 31, 2011. The rates that would take effect also include no change in depreciation rates.
- The signing parties agree to implement an earnings test, in which customers and shareholders will share earnings above an ROE of 10 percent. The sharing mechanism is as follows:

ROE	Shareholders	Customers
> 10.0% ≤ 10.2%	40%	60%
> 10.2% ≤ 10.5%	50	50
> 10.5%	-	100

- PSCo agrees that it will not file for an electric rate increase that would take effect prior to Jan. 1, 2015, provided that net revenue requirements increases or decreases in excess of $10 million caused by changes in tax law, government mandates, or natural disasters may be deferred or recovered through a modified rate adjustment. In the event normalized base revenues in either 2012 or 2013 are 2.0 percent below 2011 actual levels adjusted to reflect the rate increases allowed for 2012 and 2013, PSCo has the right to an additional rate adjustment in the next year for 50 percent of the shortfall. The parties acknowledge that PSCo may file an electric rate increase as early as May 1, 2014, so long as no rate increase takes effect on either an interim or permanent basis prior to Jan. 1, 2015.

Pending and Recently Concluded Regulatory Proceedings — Federal Energy Regulatory Commission (FERC)

PSCo 2011 Wholesale Electric Rate Case — In February 2011, PSCo filed with the FERC to change Colorado wholesale electric rates to formula based rates with an expected annual increase of $16.1 million for 2011. The request was based on a 2011 forecast test year, a 10.9 percent ROE, a rate base of $407.4 million and an equity ratio of 57.1 percent. The formula rate would be estimated each year for the following year and then trued-up to actual costs after the conclusion of the calendar year. In September 2011, PSCo implemented an interim rate increase of $7.8 million, subject to refund.

In April 2012, PSCo filed an unopposed settlement agreement with wholesale customers for an annual rate increase of $7.8 million. The primary reasons for the decrease from the original request were a reduction to depreciation expense of $5.8 million and a lower ROE (ranging from 10.1 percent to 10.4 percent). The reduction of depreciation expense is associated with the early retirement of plants related to PSCo's compliance with the CACJA. The depreciation expense will be deferred and amortized over the original life of the plants.

PSCo Transmission Formula Rate Case — In April 2012, PSCo filed with the FERC to revise the wholesale transmission rates formula from a historic test year formula rate to a forecast transmission formula. PSCo proposed that the formula rates be updated annually to reflect changes in costs, subject to a true-up. The request would increase PSCo's transmission revenue by approximately $2.0 million over rates expected to be effective in June 2012. A FERC decision is expected in the second half of 2012.

Electric, Purchased Gas and Resource Adjustment Clauses

Renewable Energy Credit (REC) Sharing — In May 2011, the CPUC determined that margin sharing on stand-alone REC transactions would be shared 20 percent to PSCo and 80 percent to customers beginning in 2011 and ultimately becoming 10 percent to PSCo and 90 percent to customers by 2014. The CPUC also approved a change to the treatment of hybrid REC trading margins (RECs that are bundled with energy) that allows the customers' share of the margins to be netted against the renewable energy standard adjustment (RESA) regulatory asset balance. In the second quarter of 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

In the first quarter of 2012, the CPUC approved an annual margin sharing on the first $20 million of margins on hybrid REC trades of 80 percent to the customers and 20 percent to PSCo. Margins in excess of the $20 million are to be shared 90 percent to the customers and 10 percent to PSCo. The CPUC authorized PSCo to return to customers unspent carbon offset funds by crediting the RESA regulatory asset balance. In March 2012, PSCo credited approximately $28.7 million against the RESA regulatory asset balance.

This sharing mechanism will be effective through 2014 to provide the CPUC an opportunity to review the framework and to review evidence regarding actual deliveries in relatively more complex markets such as California.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5, the circumstances set forth in Notes 12, 13 and 14 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011, appropriately represent, in all material respects, the current status of commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to Xcel Energy's financial position.

Purchased Power Agreements

Under certain purchased power agreements, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities that own natural gas or biomass fueled power plants for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific purchased power agreements create a variable interest in the associated independent power producing entity.

Xcel Energy had approximately 3,773 megawatts (MW) of capacity under long-term purchased power agreements as of March 31, 2012 and Dec. 31, 2011 with entities that have been determined to be variable interest entities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. These agreements have expiration dates through the year 2033.

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of March 31, 2012 and Dec. 31, 2011, Xcel Energy Inc. and its subsidiaries have no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

The following table presents guarantees and bond indemnities issued and outstanding for Xcel Energy Inc.:

(Millions of Dollars)	March 31, 2012	Dec. 31, 2011
Guarantees issued and outstanding	$ 67.5	$ 67.5
Current exposure under these guarantees	17.9	18.0
Bonds with indemnity protection	30.4	31.2

Indemnification Agreements

In connection with the acquisition of the 201 MW Nobles wind project in 2011, NSP-Minnesota agreed to indemnify the seller for losses arising out of a breach of certain representations and warranties. NSP-Minnesota's indemnification obligation is capped at $20 million, in the aggregate. The indemnification obligation expires in March 2013. NSP-Minnesota has not recorded a liability related to this indemnity.

In connection with the acquisition of 900 MW of gas-fired generation from subsidiaries of Calpine Development Holdings Inc. in 2010, PSCo agreed to indemnify the seller for losses arising out of a breach of certain representations and warranties. The aggregate liability for PSCo pursuant to these indemnities is not subject to a capped dollar amount. The indemnification obligation expires in December 2012. PSCo has not recorded a liability related to this indemnity.

Xcel Energy Inc. and its subsidiaries provide other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including due organization, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of time and amount. The maximum potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

Environmental Contingencies

Manufactured Gas Plant (MGP) Sites

Ashland MGP Site — NSP-Wisconsin has been named a potentially responsible party (PRP) for contamination at a site in Ashland, Wis. The Ashland/ Northern States Power Lakefront Superfund Site (the Ashland site) includes property owned by NSP-Wisconsin, which was a site previously operated by a predecessor company as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park), on which an unaffiliated third party previously operated a sawmill and conducted creosote treating operations; and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

The U.S. Environmental Protection Agency (EPA) issued its Record of Decision (ROD) in September 2010, which documents the remedy that the EPA has selected for the cleanup of the Ashland site. In April 2011, the EPA issued special notice letters identifying several entities, including NSP-Wisconsin, as PRPs, for future cleanup at the site. The special notice letters requested that those PRPs participate in negotiations with the EPA regarding how the PRPs intend to conduct or pay for the cleanup. In June 2011, NSP-Wisconsin submitted a settlement offer to the EPA related to the future cleanup of the Ashland site. In July 2011, the EPA informed NSP-Wisconsin and the other PRPs that it was rejecting all of their individual offers and can now choose to initiate enforcement actions at any time. Despite this decision, the EPA also indicated a willingness to continue settlement negotiations with NSP-Wisconsin, which are currently ongoing.

At March 31, 2012 and Dec. 31, 2011, NSP-Wisconsin had recorded a liability of $104.3 million, based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $26.6 million was considered a current liability. NSP-Wisconsin's potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change until after negotiations or litigation with the EPA and other PRPs are fully resolved. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Ashland site include, but are not limited to, the cleanup approach implemented, which party implements the cleanup, the timing of when the cleanup is implemented and the contributions, if any, by other PRPs.

NSP-Wisconsin has deferred, as a regulatory asset, the estimated site remediation expenses and spending to date less insurance and rate recoveries, based on an expectation that the Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized in NSP-Wisconsin rates recovery of all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin retail rate case process. Under an existing PSCW policy with respect to recovery of remediation costs for MGPs, utilities have recovered remediation costs in natural gas rates, amortized over a four to six year period. The PSCW has not allowed utilities to recover their carrying costs on unamortized regulatory assets for MGP remediation. In a recent rate case decision, the PSCW recognized the potential magnitude of the future liability for, and circumstances of, the cleanup at the Ashland site and indicated it may consider alternatives to its established MGP site cleanup cost accounting and cost recovery guidelines for the Ashland site in a future proceeding. NSP-Wisconsin is working with the PSCW Staff to develop alternatives for consideration by the PSCW.

Other MGP Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP sites where hazardous or other regulated materials may have been deposited. Xcel Energy has identified eight sites where former MGP activities have or may have resulted in actual site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any ultimate remediation that may be conducted. Xcel Energy anticipates that the majority of the remediation at these sites will continue through at least 2014. For these sites, Xcel Energy had accrued $4.0 million and $3.9 million at March 31, 2012 and Dec. 31, 2011, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs actually incurred at these sites. Xcel Energy anticipates that any amounts actually spent will be fully recovered from customers.

Other Environmental Requirements

Greenhouse Gas (GHG) New Source Performance Standard Proposal (NSPS) and Emission Guideline for Existing Sources — The EPA plans to propose GHG regulations applicable to emissions from new and existing power plants under the Clean Air Act (CAA). In April 2012, the EPA proposed a GHG NSPS for newly constructed power plants. The proposal requires that carbon dioxide (CO_2) emission rates be equal to those achieved by a natural gas combined cycle plant, even if the plant is coal-fired. The EPA also proposed that NSPS not apply to modified or reconstructed existing power plants and noted that, pursuant to its general NSPS regulations, installation of control equipment on existing plants would not constitute a “modification” to those plants under the NSPS program. It is not possible to evaluate the impact of this regulation until its final requirements are known. It is not known when the EPA will propose standards for existing sources.

New Mexico GHG Regulations — In 2010, the New Mexico Environmental Improvement Board (EIB) adopted two regulations to limit GHG emissions, including CO_2 emissions from power plants and other industrial sources. SPS, other utilities and industry groups have filed separate appeals with the New Mexico Court of Appeals challenging the validity of these two GHG regulations. The appellate cases have been stayed pending further proceedings before the EIB.

In July 2011, SPS and other parties filed a petition for repeal of each GHG rule with the EIB. The EIB repealed both regulations in February 2012 and in March 2012. In April 2012, Western Resource Advocates and New Energy Economy, Inc. filed an appeal with the New Mexico Court of Appeals to challenge the EIB’s February decision to repeal the GHG cap-and-trade program rule. SPS has filed a petition to intervene in the appeal.

Cross-State Air Pollution Rule (CSAPR) — In July 2011, the EPA issued its CSAPR to address long range transport of particulate matter and ozone by requiring reductions in sulfur dioxide (SO_2) and nitrogen oxide (NOx) from utilities located in the eastern half of the United States. For Xcel Energy, the rule applies to Minnesota, Wisconsin and Texas. The CSAPR sets more stringent requirements than the proposed Clean Air Transport Rule and specifically requires plants in Texas to reduce their SO_2 and annual NOx emissions. The rule also creates an emissions trading program.

On Dec. 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a stay of the CSAPR, pending completion of judicial review. Oral arguments in the case were held in April 2012 and it is anticipated the D.C. Circuit will rule on the challenges to the CSAPR in the second half of 2012. It is not known at this time whether the CSAPR will be upheld, reversed or will require modifications pursuant to a future D.C. Circuit decision.

If the CSAPR is upheld and unmodified, Xcel Energy believes that the CSAPR could ultimately require the installation of additional emission controls on some of SPS’ coal-fired electric generating units. If compliance is required in a short time frame, SPS may be required to redispatch its system to reduce coal plant operating hours, in order to decrease emissions from its facilities prior to the installation of emission controls. The expected cost for these scenarios may vary significantly and SPS has estimated capital expenditures of approximately $470 million over the next four years for the plant modifications related to the CSAPR requirements. SPS believes the cost of any required capital investment or possible increased fuel costs would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position or cash flows. On April 23, 2012, SPS appealed to the D.C. Circuit on a final rule that the EPA issued that made changes to certain allowance allocations under CSAPR. While this rule increases the allowance allocations for SO_2 for SPS, it did not increase them by as much as the proposed rule. SPS is seeking additional allowance allocations through this appeal, which, if successful, would reduce SPS’ costs to comply with the CSAPR.

If the CSAPR is upheld and unmodified**,** NSP-Minnesota would likely utilize a combination of emissions reductions through upgrades to its existing SO_2 control technology at NSP-Minnesota’s Sherco plant, which is estimated to cost a total of $10 million through 2014, and system operating changes to the Black Dog and the Sherco plants. If available, NSP-Minnesota would also consider allowance purchases. In addition, NSP-Minnesota has filed a petition for reconsideration with the EPA and a petition for review of the CSAPR with the D.C. Circuit seeking the allocation of additional emission allowances to NSP-Minnesota. NSP-Minnesota contends that the EPA’s method of allocating allowances arbitrarily resulted in fewer allowances for its Riverside and High Bridge plants than should have been awarded to reflect their operations during the baseline period, which included coal-fired operations prior to their conversion to natural gas. On April 23, 2012, NSP-Minnesota appealed to the D.C. Circuit on a final rule that the EPA issued that made changes to certain allowance allocations under CSAPR, seeking to secure additional allocations for its Riverside and High Bridge plants. If successful, additional allowances would reduce NSP-Minnesota’s costs to comply with the CSAPR.

If the CSAPR is upheld and unmodified, NSP-Wisconsin would likely make a combination of system operating changes and allowance purchases. NSP-Wisconsin estimates the cost of compliance would be $0.2 million, and expects the cost of any required capital investment will be recoverable from customers.

Electric Generating Unit (EGU) Mercury and Air Toxics Standards (MATS) Rule — The final EGU MATS rule became effective April 2012. The EGU MATS rule sets emission limits for acid gases, mercury and other hazardous air pollutants and requires coal-fired utility facilities greater than 25 MW to demonstrate compliance within three to four years of the effective date. Xcel Energy believes these costs will be recoverable through regulatory mechanisms and does not expect a material impact on results of operations, financial position or cash flows.

Regional Haze Rules — In 2005, the EPA finalized amendments to its regional haze rules regarding provisions that require the installation and operation of emission controls, known as best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas throughout the United States. Xcel Energy generating facilities in several states will be subject to BART requirements. Individual states are required to identify the facilities located in their states that will have to reduce SO_2, NOx and particulate matter emissions under BART and then set emissions limits for those facilities.

PSCo

In 2006, the Colorado Air Quality Control Commission promulgated BART regulations requiring certain major stationary sources to evaluate, install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. In January 2011, the Colorado Air Quality Control Commission approved a revised Regional Haze BART state implementation plan (SIP) incorporating the Colorado CACJA emission reduction plan, which will satisfy regional haze requirements. In March 2012, the EPA proposed to approve the Colorado SIP, including the CACJA emission reduction plan for PSCo, as satisfying BART requirements. PSCo expects the cost of any required capital investment will be recoverable from customers through the CACJA plan recovery mechanisms or other regulatory mechanisms. Emissions controls are expected to be installed between 2012 and 2017.

In March 2010, two environmental groups petitioned the U.S. Department of the Interior (DOI) to certify that 12 coal-fired boilers and one coal-fired cement kiln in Colorado are contributing to visibility problems in Rocky Mountain National Park. The following PSCo plants are named in the petition: Cherokee, Hayden, Pawnee and Valmont. The groups allege that the Colorado BART rule is inadequate to satisfy the CAA mandate of ensuring reasonable further progress towards restoring natural visibility conditions in the park. It is not known when the DOI will rule on the petition.

NSP-Minnesota

In December 2009, the Minnesota Pollution Control Agency (MPCA) approved the Regional Haze SIP, which has been submitted to the EPA for approval. The MPCA selected the BART controls for Sherco Units 1 and 2 to improve visibility in the national parks. The MPCA concluded Selective Catalytic Reduction (SCR) should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The MPCA's BART controls for Sherco Units 1 and 2 consist of combustion controls for NOx and scrubber upgrades for SO_2. The combustion controls have been installed on Sherco Units 1 and 2, and the scrubber upgrades are scheduled to be installed by 2015. At this time, the estimated cost for meeting the BART and other CAA requirements is approximately $50 million, of which $20 million has already been spent on projects to reduce NOx emissions on Sherco Units 1 and 2. Xcel Energy anticipates that all costs associated with BART compliance will be fully recoverable.

In June 2011, the EPA provided comments to the MPCA on the SIP, stating that the EPA's preliminary review indicates that SCR controls should be added to Sherco Units 1 and 2. The MPCA has since proposed that the CSAPR should be considered BART for EGUs and the EPA has proposed that states be allowed to find that CSAPR compliance meets BART requirements for EGUs, and specifically that Minnesota's proposal to find the CSAPR to meet BART requirements should be approved, if finalized by the state.

On April 24, 2012, the MPCA approved a supplement to the 2009 Regional Haze SIP finding that CSAPR meets BART for EGUs in Minnesota. The supplement also made a source-specific BART determination for Sherco Units 1 and 2 that requires installation of the combustion controls for NOx and scrubber upgrades for SO_2 by January 2015. This SIP supplement will be forwarded to the EPA for approval, and it is anticipated that the EPA will make a decision in May 2012.

In addition to the Regional Haze rules identified in the EPA's visibility program, and addressed in the MPCA's SIP discussed above, there are other visibility rules related to a program called the Reasonably Attributable Visibility Impairment (RAVI) program. In October 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2. The EPA is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to RAVI and, if so, whether the level of controls required by the MPCA is appropriate. The EPA plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program. It is not yet known when the EPA will publish a proposal under RAVI, or what that proposal will entail.

SPS
Harrington Units 1 and 2 are potentially subject to BART. Texas has developed a Regional Haze SIP that finds the Clean Air Interstate Rule (CAIR) equal to BART for EGUs, and as a result, no additional controls for these units beyond the CAIR compliance would be required. The EPA is scheduled to publish its proposal of the Texas plan in May 2012 and complete its review by November 2012.

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material effect on Xcel Energy's consolidated financial position, results of operations, and cash flows.

Environmental Litigation

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other utility, oil, gas and coal companies. Plaintiffs claim that defendants' emission of CO_2 and other GHGs contribute to global warming, which is harming their village. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss in June 2008. In October 2009, the U.S. District Court dismissed the lawsuit on constitutional grounds. In November 2009, plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit. In November 2011, oral arguments were presented. It is unknown when the Ninth Circuit will render a final opinion. The amount of damages claimed by plaintiffs is unknown, but likely includes the cost of relocating the village of Kivalina. Plaintiffs' alleged relocation is estimated to cost between $95 million to $400 million. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it could potentially have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

Comer vs. Xcel Energy Inc. et al. — In May 2011, less than a year after their initial lawsuit was dismissed, plaintiffs in this purported class action lawsuit filed a second lawsuit against more than 85 utility, oil, chemical and coal companies in U.S. District Court in Mississippi. The complaint alleges defendants' CO_2 emissions intensified the strength of Hurricane Katrina and increased the damage plaintiffs purportedly sustained to their property. Plaintiffs base their claims on public and private nuisance, trespass and negligence. Among the defendants named in the complaint are Xcel Energy Inc., SPS, PSCo, NSP-Wisconsin and NSP-Minnesota. The amount of damages claimed by plaintiffs is unknown. The defendants, including Xcel Energy Inc., believe this lawsuit is without merit and filed a motion to dismiss the lawsuit. On March 20, 2012, the U.S. District Court granted this motion for dismissal. In April 2012, plaintiffs appealed this decision to the U.S. Court of Appeals for the Fifth Circuit. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it could potentially have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

Employment, Tort and Commercial Litigation

***Merricourt Wind Project Litigation* —** In April 2011, NSP-Minnesota terminated its agreements with enXco Development Corporation (enXco) for the development of a 150 MW wind project in southeastern North Dakota. NSP-Minnesota's decision to terminate the agreements was based in large part on the adverse impact this project could have on endangered or threatened species protected by federal law and the uncertainty in cost and timing in mitigating this impact. NSP-Minnesota also terminated the agreements due to enXco's nonperformance of certain other conditions, including failure to obtain a Certificate of Site Compatibility and the failure to close on the contracts by an agreed upon date of March 31, 2011. As a result, NSP-Minnesota recorded a $101 million deposit in the first quarter of 2011, which was collected in April 2011. In May 2011, NSP-Minnesota filed a declaratory judgment action in U.S. District Court in Minnesota to obtain a determination that it acted properly in terminating the agreements and enXco also filed a separate lawsuit in the same court seeking, among other things, in excess of $240 million for an alleged breach of contract. NSP-Minnesota believes enXco's lawsuit is without merit and has filed a motion to dismiss. In September 2011, the U.S. District Court denied the motion to dismiss. The trial is set to begin in late 2012 or early 2013. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it could potentially have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

7. Borrowings and Other Financing Instruments

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated upon consolidation.

Commercial Paper — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities. Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2012	Twelve Months Ended Dec. 31, 2011
Borrowing limit	$ 2,450	$ 2,450
Amount outstanding at period end	339	219
Average amount outstanding	324	430
Maximum amount outstanding	463	824
Weighted average interest rate, computed on a daily basis	0.36%	0.36%
Weighted average interest rate at period end	0.36	0.40

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit agreements. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

At March 31, 2012, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility	Drawn (a)	Available
Xcel Energy Inc.	$ 800.0	$ 214.0	$ 586.0
PSCo	700.0	3.0	697.0
NSP-Minnesota	500.0	35.7	464.3
SPS	300.0	26.0	274.0
NSP-Wisconsin	150.0	71.0	79.0
Total	$ 2,450.0	$ 349.7	$ 2,100.3

(a) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at March 31, 2012 and Dec. 31, 2011.

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At March 31, 2012 and Dec. 31, 2011, there were $10.7 million and $12.7 million of letters of credit outstanding, respectively, under the credit facilities. An additional $1.1 million of letters of credit not issued under the credit facilities were outstanding at March 31, 2012 and Dec. 31, 2011, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with discounted cash flow or option pricing models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on NSP-Minnesota's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities, except for asset-backed and mortgage-backed securities, for which the third party service may also consider additional, more subjective inputs. Since the impact of the use of these less observable inputs can be significant to the valuation of asset-backed and mortgage-backed securities, fair value measurements for these instruments have been assigned a Level 3. Inputs that may be considered in the valuation of asset-backed and mortgage-backed securities in conjunction with pricing of similar securities in active markets include the use of risk-based discounting and estimated prepayments in a discounted cash flow model. When these additional inputs and models are utilized, increases in the risk-adjusted discount rates and decreases in the assumed principal prepayment rates each have the impact of reducing reported fair values for these instruments.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include financial transmission rights (FTRs) purchased from Midwest Independent Transmission System Operator, Inc. (MISO). FTRs purchased from MISO are financial instruments that entitle the holder to one year of monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of that energy congestion, which is caused by overall transmission load and other transmission constraints. Congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. NSP-Minnesota's valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Monthly FTR settlements are included in the fuel clause adjustment, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivatives, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy's own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of interest rate derivatives and commodity derivatives presented in the consolidated balance sheets.

Non-Derivative Instruments Fair Value Measurements

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and Prairie Island nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the decommissioning fund were $117.1 million and $79.8 million at March 31, 2012 and Dec. 31, 2011, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $65.7 million and $87.5 million at March 31, 2012 and Dec. 31, 2011, respectively.

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at March 31, 2012 and Dec. 31, 2011:

	March 31, 2012				
		Fair Value			
(Thousands of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**Total**
Nuclear decommissioning fund (a)					
Cash equivalents	$ 12,383	$ 8,023	$ 4,360	$ -	$ 12,383
Commingled funds	374,523	-	371,078	-	371,078
International equity funds	65,712	-	67,183	-	67,183
Private equity investments	19,358	-	-	20,068	20,068
Real estate	26,265	-	-	27,905	27,905
Debt securities:					
Government securities	131,152	-	131,401	-	131,401
U.S. corporate bonds	156,602	-	163,851	-	163,851
International corporate bonds	25,187	-	26,351	-	26,351
Municipal bonds	53,895	-	56,862	-	56,862
Asset-backed securities	16,515	-	-	16,547	16,547
Mortgage-backed securities	65,803	-	-	68,671	68,671
Equity securities:					
Common stock	410,729	447,205	-	-	447,205
Total	$1,358,124	$455,228	$821,086	$133,191	$1,409,505

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $92.3 million of equity investments in unconsolidated subsidiaries and $35.7 million of miscellaneous investments.

(Thousands of Dollars)	Dec. 31, 2011 Cost	Fair Value Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$ 26,123	$ 7,103	$ 19,020	$ -	$ 26,123
Commingled funds	320,798	-	311,105	-	311,105
International equity funds	63,781	-	58,508	-	58,508
Private equity investments	9,203	-	-	9,203	9,203
Real estate	24,768	-	-	26,395	26,395
Debt securities:					
Government securities	116,490	-	117,256	-	117,256
U.S. corporate bonds	187,083	-	193,516	-	193,516
International corporate bonds	35,198	-	35,804	-	35,804
Municipal bonds	60,469	-	64,731	-	64,731
Asset-backed securities	16,516	-	-	16,501	16,501
Mortgage-backed securities	75,627	-	-	78,664	78,664
Equity securities:					
Common stock	408,122	398,625	-	-	398,625
Total	$1,344,178	$405,728	$799,940	$130,763	$1,336,431

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $92.7 million of equity investments in unconsolidated subsidiaries and $34.3 million of miscellaneous investments.

The following tables present the changes in Level 3 nuclear decommissioning fund investments:

(Thousands of Dollars)	Jan. 1, 2012	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	March 31, 2012
Asset-backed securities	$ 16,501	$ -	$ (1)	$ 47	$ 16,547
Mortgage-backed securities	78,664	6,904	(16,728)	(169)	68,671
Real estate	26,395	1,636	(1,766)	1,640	27,905
Private equity investments	9,203	10,155	-	710	20,068
Total	$ 130,763	$ 18,695	$ (18,495)	$ 2,228	$ 133,191

(Thousands of Dollars)	Jan. 1, 2011	Purchases	Settlements	Losses Recognized as Regulatory Assets	March 31, 2011
Asset-backed securities	$ 33,174	$ 756	$ (7,910)	$ -	$ 26,020
Mortgage-backed securities	72,589	46,113	(19,873)	(462)	98,367
Total	$ 105,763	$ 46,869	$ (27,783)	$ (462)	$ 124,387

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class at March 31, 2012:

(Thousands of Dollars)	Final Contractual Maturity Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$ 113,004	$ 701	$ 17,696	$ -	$131,401
U.S. corporate bonds	-	37,556	112,103	14,192	163,851
International corporate bonds	-	8,162	18,186	3	26,351
Municipal bonds	-	-	27,039	29,823	56,862
Asset-backed securities	-	13,269	3,278	-	16,547
Mortgage-backed securities	-	-	959	67,712	68,671
Debt securities	$ 113,004	$ 59,688	$ 179,261	$ 111,730	$463,683

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to reduce risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices, as well as variances in forecasted weather.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At March 31, 2012, accumulated other comprehensive losses related to interest rate derivatives included $0.9 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

At March 31, 2012, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $475 million. These interest rate swaps were designated as hedges, and as such, changes in fair value are recorded to OCI.

Short-Term Wholesale and Commodity Trading Risk — Xcel Energy conducts various short-term wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale and vehicle fuel.

At March 31, 2012, Xcel Energy had various vehicle fuel related contracts designated as cash flow hedges extending through December 2014. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the three months ended March 31, 2012 and 2011.

At March 31, 2012, accumulated OCI related to commodity derivative cash flow hedges included $0.2 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at March 31, 2012 and Dec. 31, 2011:

(Amounts in Thousands) (a)(b)	**March 31, 2012**	**Dec. 31, 2011**
Megawatt hours (MWh) of electricity	23,385	38,822
MMBtu of natural gas	-	40,736
Gallons of vehicle fuel	550	600

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

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The following tables detail the impact of derivative activity during the three months ended March 31, 2012 and 2011, on OCI, regulatory assets and liabilities, and income:

	Three Months Ended March 31, 2012				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ 41,704	$ -	$ 389(a)	$ -	$ -
Vehicle fuel and other commodity	179	-	(52)(e)	-	-
Total	$ 41,883	$ -	$ 337	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 1,723(b)
Electric commodity	-	1,582	-	(7,972)(c)	-
Natural gas commodity	-	(10,783)	-	80,939(d)	(109)(b)
Total	$ -	$ (9,201)	$ -	$ 72,967	$ 1,614

	Three Months Ended March 31, 2011				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ -	$ -	$ 337(a)	$ -	$ -
Vehicle fuel and other commodity	389	-	(32)(e)	-	-
Total	$ 389	$ -	$ 305	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 5,600(b)
Electric commodity	-	8,846	-	(8,888)(c)	-
Natural gas commodity	-	(7,615)	-	57,387(d)	-
Total	$ -	$ 1,231	$ -	$ 48,499	$ 5,600

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Recorded to O&M expenses.

Xcel Energy had no derivative instruments designated as fair value hedges during the three months ended March 31, 2012 and March 31, 2011. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Credit Related Contingent Features — Contract provisions of the derivative instruments that the utility subsidiaries enter into may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. If the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade, contracts underlying $10.8 million and $8.3 million of derivative instruments in a gross liability position at March 31, 2012 and Dec. 31, 2011, respectively, would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle applicable contracts, which would have resulted in payments to counterparties of $9.4 million and $9.3 million, respectively. At March 31, 2012 and Dec. 31, 2011, there was no collateral posted on these specific contracts.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of March 31, 2012 and Dec. 31, 2011.

Recurring Fair Value Measurements — The following tables present for each of the hierarchy levels, Xcel Energy's derivative assets and liabilities that are measured at fair value on a recurring basis at March 31, 2012:

	March 31, 2012					
	Fair Value					
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Counterparty Netting (b)**	**Total**
Current derivative assets						
Derivatives designated as cash flow hedges:						
Interest rate	$ -	$ 306	$ -	$ 306	$ -	$ 306
Vehicle fuel and other commodity	-	208	-	208	-	208
Other derivative instruments:						
Trading commodity	-	39,483	-	39,483	(16,195)	23,288
Electric commodity	-	-	5,898	5,898	(570)	5,328
Total current derivative assets	$ -	$39,997	$ 5,898	$ 45,895	$ (16,765)	29,130
Purchased power agreements (a)						32,841
Current derivative instruments						$ 61,971
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ -	$ 209	$ -	$ 209	$ (115)	$ 94
Other derivative instruments:						
Trading commodity	-	38,214	-	38,214	(5,470)	32,744
Total noncurrent derivative assets	$ -	$38,423	$ -	$ 38,423	$ (5,585)	32,838
Purchased power agreements (a)						113,600
Noncurrent derivative instruments						$146,438

	March 31, 2012					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Interest rate	$ -	$16,352	$ -	$ 16,352	$ -	$ 16,352
Other derivative instruments:						
Trading commodity	-	34,130	4	34,134	(17,272)	16,862
Electric commodity	-	-	570	570	(570)	-
Total current derivative liabilities	$ -	$50,482	$ 574	$ 51,056	$ (17,842)	33,214
Purchased power agreements (a)						22,918
Current derivative instruments						$ 56,132
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$ -	$22,918	$ -	$ 22,918	$ (5,585)	$ 17,333
Total noncurrent derivative liabilities	$ -	$22,918	$ -	$ 22,918	$ (5,585)	17,333
Purchased power agreements (a)						242,819
Noncurrent derivative instruments						$260,152

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) The accounting guidance for derivatives and hedging permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

The following tables present for each of the hierarchy levels, Xcel Energy's derivative assets and liabilities that are measured at fair value on a recurring basis at Dec. 31, 2011:

	Dec. 31, 2011					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ -	$ 169	$ -	$ 169	$ (76)	$ 93
Other derivative instruments:						
Trading commodity	-	32,682	-	32,682	(13,391)	19,291
Electric commodity	-	-	13,333	13,333	(1,471)	11,862
Total current derivative assets	$ -	$32,851	$13,333	$ 46,184	$ (14,938)	31,246
Purchased power agreements (a)						33,094
Current derivative instruments						$ 64,340
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$ -	$ 107	$ -	$ 107	$ (59)	$ 48
Other derivative instruments:						
Trading commodity	-	36,599	-	36,599	(5,540)	31,059
Total noncurrent derivative assets	$ -	$36,706	$ -	$ 36,706	$ (5,599)	31,107
Purchased power agreements (a)						121,780
Noncurrent derivative instruments						$152,887

(Thousands of Dollars)	Dec. 31, 2011 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Interest rate	$ -	$ 57,749	$ -	$ 57,749	$ -	$ 57,749
Other derivative instruments:						
Trading commodity	-	27,891	-	27,891	(14,417)	13,474
Electric commodity	-	698	916	1,614	(1,471)	143
Natural gas commodity	418	70,119	-	70,537	(7,486)	63,051
Total current derivative liabilities	$ 418	$156,457	$ 916	$ 157,791	$ (23,374)	134,417
Purchased power agreements (a)						22,997
Current derivative instruments						$157,414
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$ -	$ 20,966	$ -	$ 20,966	$ (5,599)	$ 15,367
Total noncurrent derivative liabilities	$ -	$ 20,966	$ -	$ 20,966	$ (5,599)	15,367
Purchased power agreements (a)						248,539
Noncurrent derivative instruments						$263,906

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) The accounting guidance for derivatives and hedging permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

The following table presents the changes in Level 3 commodity derivatives for the three months ended March 31, 2012 and 2011:

(Thousands of Dollars)	Three Months Ended March 31 2012	2011
Balance at Jan. 1	$ 12,417	$ 2,392
Settlements	(8,884)	(7,790)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings (a)	(9)	68
Gains recognized as regulatory liabilities	1,800	7,662
Balance at March 31	$ 5,324	$ 2,332

(a) These amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for the three months ended March 31, 2012 and March 31, 2011.

Fair Value of Long-Term Debt

As of March 31, 2012 and Dec. 31, 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	March 31, 2012		Dec. 31, 2011	
(Thousands of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 9,908,044	$ 11,414,894	$ 9,908,435	$ 11,734,798

The fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of March 31, 2012 and Dec. 31, 2011, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2. These fair value estimates have not been comprehensively revalued for purposes of these consolidated financial statements since those dates and current estimates of fair values may differ significantly.

9. Other Income, Net

Other income (expense), net consisted of the following:

	Three Months Ended March 31	
(Thousands of Dollars)	**2012**	**2011**
Interest income	$ 5,622	$ 4,773
Other nonoperating income	922	864
Insurance policy expense	(2,799)	(871)
Other nonoperating expense	(8)	-
Other income, net	$ 3,737	$ 4,766

10. Segment Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits, and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas, and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $92.3 million and $92.7 million as of March 31, 2012 and Dec. 31, 2011, respectively, included in the regulated natural gas segment.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from continuing operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2012					
Operating revenues from external customers	$ 1,936,782	$ 621,035	$ 20,262	$ -	$ 2,578,079
Intersegment revenues	302	499	-	(801)	-
Total revenues	$ 1,937,084	$ 621,534	$ 20,262	$ (801)	$ 2,578,079
Income (loss) from continuing operations	$ 143,221	$ 50,202	$ (9,654)	$ -	$ 183,769

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2011					
Operating revenues from external customers	$ 2,029,972	$ 765,349	$ 21,219	$ -	$ 2,816,540
Intersegment revenues	339	799	-	(1,138)	-
Total revenues	$ 2,030,311	$ 766,148	$ 21,219	$ (1,138)	$ 2,816,540
Income (loss) from continuing operations	$ 154,637	$ 58,597	$ (9,767)	$ -	$ 203,467

11. Earnings Per Share

Basic earnings per share (EPS) was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents), such as share-based compensation awards were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated based on the treasury stock method.

Share-Based Compensation
Common stock equivalents related to share-based compensation causing dilutive impact to EPS currently consist of 401(k) equity awards. Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted, pending remaining service conditions.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Restricted stock unit equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Performance share plan liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

The dilutive impact of common stock equivalents affecting EPS was as follows:

(Amounts in thousands, except per share data)	Three Months Ended March 31, 2012 Income	Shares	Per Share Amount	Three Months Ended March 31, 2011 Income	Shares	Per Share Amount
Net income	$ 183,893			$ 203,569		
Less: Dividend requirements on preferred stock	-			(1,060)		
Basic earnings per share:						
Earnings available to common shareholders	183,893	487,360	$ 0.38	202,509	483,641	$ 0.42
Effect of dilutive securities:						
401(k) equity awards	-	635		-	660	
Diluted earnings per share:						
Earnings available to common shareholders	$ 183,893	487,995	$ 0.38	$ 202,509	484,301	$ 0.42

For the three months ended March 31, 2011, Xcel Energy Inc. had approximately 2.5 million weighted average stock options outstanding that were antidilutive, and therefore, excluded from the EPS calculation. No stock options were outstanding at March 31, 2012.

Share Repurchase — In February 2012, Xcel Energy Inc.'s Board of Directors approved the repurchase of up to 0.7 million shares of common stock for the issuance of shares in connection with the vesting of awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan. In March 2012, Xcel Energy Inc. repurchased the approved 0.7 million shares in the open market at an average price of $26.42 per share. In addition, approximately 0.9 million shares of common stock were purchased in February 2012 through an agent independent of Xcel Energy to fulfill requirements for the employer match pursuant to the Xcel Energy 401(k) Savings Plan; the New Century Energies, Inc. Employees' Savings and Stock Ownership Plan for Bargaining Unit Employees and Former Non-Bargaining Unit Employees; and the New Century Energies, Inc. Employee Investment Plan for Bargaining Unit Employees and Non-Bargaining Employees.

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended March 31			
	2012	2011	2012	2011
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 21,329	$ 18,112	$ 1,180	$ 1,315
Interest cost	38,723	39,915	9,380	10,551
Expected return on plan assets	(51,476)	(55,286)	(7,111)	(7,968)
Amortization of transition obligation	-	-	3,580	3,611
Amortization of prior service cost (credit)	5,266	5,633	(1,888)	(1,233)
Amortization of net loss	26,318	18,729	3,965	3,343
Net periodic benefit cost	40,160	27,103	9,106	9,619
Costs not recognized and additional cost recognized due to the effects of regulation	(9,133)	(7,885)	973	973
Net benefit cost recognized for financial reporting	$ 31,027	$ 19,218	$ 10,079	$ 10,592

In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2012.

Item 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy's financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and the related notes to consolidated financial statements. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy Inc. and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including "Risk Factors" in Item 1A of Xcel Energy Inc.'s Form 10-K for the year ended Dec. 31, 2011, and Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.

Financial Review

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The earnings and EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. EPS by subsidiary is a financial measure not recognized under GAAP that is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Xcel Energy's management uses this non-GAAP financial measure to evaluate and provide details of earnings results. Xcel Energy's management believes that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. This non-GAAP financial measure should not be considered as an alternative to Xcel Energy's consolidated fully diluted EPS determined in accordance with GAAP as an indicator of operating performance.

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Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

Diluted Earnings (Loss) Per Share	Three Months Ended March 31 2012	2011
PSCo	$ 0.19	$ 0.20
NSP-Minnesota	0.16	0.19
NSP-Wisconsin	0.03	0.03
SPS	0.02	0.02
Equity earnings of unconsolidated subsidiaries	0.01	0.01
Regulated utility — continuing operations	0.41	0.45
Xcel Energy Inc. and other costs	(0.03)	(0.03)
GAAP diluted earnings per share	**$ 0.38**	**$ 0.42**

Xcel Energy — Overall, earnings decreased $0.04 per share for the first quarter of 2012.

PSCo — PSCo earnings decreased $0.01 per share for the first quarter of 2012. The decrease is mainly due to lower electric and gas sales due to warmer weather, decreased wholesale revenue due to the expiration of a long-term wholesale power agreement with Black Hills Corp., higher depreciation expense and interest charges, partially offset by higher gas revenues, primarily due to new rates effective in September 2011.

NSP-Minnesota — NSP-Minnesota earnings decreased $0.03 per share for the first quarter of 2012. The decrease is primarily the result of warmer weather impacting electric and gas sales, differences between rates effective in the first quarter of 2012 as compared to interim rates in the first quarter of 2011, higher property taxes and higher O&M expenses. The decreases were partially offset by a lower effective tax rate.

NSP-Wisconsin — NSP-Wisconsin earnings per share were flat for the first quarter of 2012. Higher electric and gas rates implemented in January 2012 and lower O&M expenses were offset by lower electric and gas sales due to warmer weather.

SPS — SPS earnings per share were flat for the first quarter of 2012. Higher electric margins in Texas and New Mexico, primarily due to rate increases effective in January 2012, were offset by the negative impact of warmer weather, higher depreciation expense, property taxes and interest charges.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in the 2012 EPS compared with the same period in 2011, which are discussed in more detail below.

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
2011 GAAP diluted earnings per share	**$ 0.42**
Components of change — 2012 vs. 2011	
Lower electric margins	(0.03)
Lower natural gas margins	(0.02)
Higher interest charges	(0.01)
Higher taxes (other than income taxes)	(0.01)
Lower effective tax rate	0.03
Lower conservation and DSM expenses (generally offset in revenues)	0.01
Other, net	(0.01)
2012 GAAP diluted earnings per share	**$ 0.38**

The following tables summarize the earnings contributions of Xcel Energy's business segments on the basis of GAAP:

Contributions to Income (Millions of Dollars)	Three Months Ended March 31 2012	2011
GAAP income (loss) by segment		
Regulated electric income	$ 143.2	$ 154.6
Regulated natural gas income	50.2	58.6
Other income (a)	7.3	5.0
Segment income — continuing operations	200.7	218.2
Xcel Energy Inc. and other costs (a)	(16.9)	(14.7)
Total income — continuing operations	183.8	203.5
Income from discontinued operations	0.1	0.1
Total GAAP net income	$ 183.9	$ 203.6

Contributions to Diluted Earnings (Loss) Per Share	Three Months Ended March 31 2012	2011
GAAP earnings (loss) by segment		
Regulated electric	$ 0.29	$ 0.32
Regulated natural gas	0.10	0.12
Other (a)	0.02	0.01
Segment earnings per share — continuing operations	0.41	0.45
Xcel Energy Inc. and other costs(a)	(0.03)	(0.03)
Total earnings per share — continuing operations	0.38	0.42
Discontinued operations	-	-
Total GAAP earnings per diluted share	$ 0.38	$ 0.42

(a) Not a reportable segment. Included in all other segment results in Note 10 to the consolidated financial statements.

Statement of Income Analysis

The following discussion summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales while, conversely, mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit, and cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less weather sensitive.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction based on the time period used by the regulator in establishing estimated volumes in the rate setting process.

There was no impact on sales in the first quarter due to THI or CDD. The percentage increase (decrease) in normal and actual HDD is provided in the following table:

	Three Months Ended March 31		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
HDD	(18.7) %	5.2%	(22.1) %

Weather — The following table summarizes the estimated impact of temperature variations on EPS compared with sales under normal weather conditions:

	Three Months Ended March 31		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
Retail electric	$ (0.023)	$ 0.007	$ (0.030)
Firm natural gas	(0.021)	0.007	(0.028)
Total	$ (0.044)	$ 0.014	$ (0.058)

Sales Growth (Decline) — The following table summarizes Xcel Energy's sales growth (decline) for actual and weather-normalized sales in 2012:

	Three Months Ended March 31		Three Months Ended March 31 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	(5.1) %	0.5%	(6.1) %	(0.6) %
Electric commercial and industrial	(0.7)	0.2	(1.8)	(0.9)
Total retail electric sales	(2.0)	0.3	(3.1)	(0.8)
Firm natural gas sales	(14.7)	1.3	(15.7)	0.2

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have little impact on electric margin. The following table details the electric revenues and margin:

	Three Months Ended March 31	
(Millions of Dollars)	2012	2011
Electric revenues	$1,937	$2,030
Electric fuel and purchased power	(864)	(932)
Electric margin	$1,073	$1,098

The following tables summarize the components of the changes in electric revenues and electric margin:

Electric Revenues

(Millions of Dollars)	Three Months Ended March 31, 2012 vs. 2011
Fuel and purchased power cost recovery	$ (65)
Estimated impact of weather	(22)
Firm wholesale (a)	(13)
Trading, including PSCo renewable energy credit sales	(7)
Conservation and DSM revenue (offset by expenses)	(4)
Transmission revenue	10
Retail rate increases (Minnesota, Texas, New Mexico, South Dakota interim, North Dakota, Wisconsin and Michigan) (b)	5
Sales mix and demand revenue	2
Conservation and DSM incentive	2
Other, net	(1)
Total decrease in electric revenues	$ (93)

(a) Decrease is primarily due to the expiration of a long-term wholesale power agreement with Black Hills Corp.

(b) NSP-Minnesota reduced depreciation expense and revenues by approximately $8 million in the first quarter of 2012 to reflect the settlement in the Minnesota electric rate case.

Electric Margin

(Millions of Dollars)	Three Months Ended March 31, 2012 vs. 2011
Estimated impact of weather	$ (22)
Firm wholesale (a)	(11)
Conservation and DSM revenue (offset by expenses)	(4)
Transmission revenue, net of costs	5
Retail rate increases (Minnesota, Texas, New Mexico, South Dakota interim, North Dakota, Wisconsin and Michigan) (b)	5
Sales mix and demand revenue	2
Conservation and DSM incentive	2
Other, net	(2)
Total decrease in electric margin	$ (25)

(a) Decrease is primarily due to the expiration of a long-term wholesale power agreement with Black Hills Corp.

(b) NSP-Minnesota reduced depreciation expense and revenues by approximately $8 million in the first quarter of 2012 to reflect the settlement in the Minnesota electric rate case.

Natural Gas Revenues and Margin

The cost of natural gas tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

	Three Months Ended March 31,	
(Millions of Dollars)	2012	2011
Natural gas revenues	$ 621	$ 765
Cost of natural gas sold and transported	(418)	(543)
Natural gas margin	$ 203	$ 222

The following tables summarize the components of the changes in natural gas revenues and natural gas margin:

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended March 31, 2012 vs. 2011
Purchased natural gas adjustment clause recovery	$ (125)
Estimated impact of weather	(21)
Conservation and DSM revenue (offset by expenses)	(9)
Retail rate increase (Colorado, Wisconsin)	3
Pipeline system integrity adjustment rider (Colorado)	3
Return on PSCo gas in storage	2
Conservation and DSM incentive	1
Other, net	2
Total decrease in natural gas revenues	$ (144)

Natural Gas Margin

(Millions of Dollars)	Three Months Ended March 31, 2012 vs. 2011
Estimated impact of weather	$ (21)
Conservation and DSM revenue (offset by expenses)	(9)
Retail rate increase (Colorado, Wisconsin)	3
Pipeline system integrity adjustment rider (Colorado)	3
Return on PSCo gas in storage	2
Conservation and DSM incentive	1
Other, net	2
Total decrease in natural gas margin	$ (19)

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $0.7 million, or 0.1 percent, for the first quarter of 2012, compared with the same period in 2011. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	Three Months Ended March 31, 2012 vs. 2011
Higher plant generation costs	$ 6
Pipeline system integrity costs	3
Lower consulting costs	(3)
Lower employee benefit expense	(2)
Other, net	(3)
Total increase in O&M expenses	$ 1

- Higher plant generation costs are attributable to a higher level of scheduled overhaul work.
- Higher pipeline system integrity costs were for verification and testing natural gas pipeline integrity. These costs are recovered through a rider in Colorado.
- Lower employee benefit expenses were driven by lower compensation and incentive expenses, partially offset by higher pension expense.

Conservation and DSM Program Expenses — Conservation and demand side management (DSM) program expenses decreased $11.6 million, or 15.4 percent for the first quarter of 2012, compared with the same period in 2011. The lower expense is primarily attributable to lower sales volumes and lower rider rates, as well as a change in the cost allocation formula used to account for electric conservation improvement program expenses at NSP-Minnesota. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — Depreciation and amortization increased $3.9 million, or 1.8 percent for the first quarter of 2012, compared with the same period in 2011. This increase is primarily due to a portion of the Monticello extended power uprate going into service in May 2011 at NSP-Minnesota, the Jones Unit 3 going into service in June 2011 at SPS and normal system expansion across Xcel Energy's service territories. The increase was partially offset by a change in depreciation lives for certain assets to reflect the settlement in the Minnesota recent electric rate case, which resulted in a reduction in depreciation expense of approximately $8 million.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $9.1 million, or 9.4 percent for the first quarter of 2012, compared with the same period in 2011. The increase is primarily due to an increase in property taxes in Minnesota. NSP-Minnesota has requested to defer incremental property taxes in Minnesota effective as of Jan. 1, 2012. However, until the MPUC rules on this issue, NSP-Minnesota will continue to expense the incremental property taxes. Assuming MPUC approval of NSP-Minnesota's request, which is currently expected in the second quarter of 2012, NSP-Minnesota would reflect the deferral retroactive to Jan. 1, 2012. See Note 5 to the consolidated financial statements for further discussion.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC decreased $0.6 million, or 3.0 percent for the first quarter of 2012, compared with the same period in 2011. The decrease is primarily due to lower average construction work in progress balances.

Interest Charges — Interest charges increased $7.5 million, or 5.2 percent for the first quarter of 2012, compared with the same period in 2011. The increase is due to higher long-term debt levels to fund investments in utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense for continuing operations decreased $36.5 million for the first quarter of 2012, compared with the same period in 2011. The decrease in income tax expense was primarily due to lower pretax earnings and a tax benefit associated with a carryback. The effective tax rate for continuing operations was 29.1 percent for the first quarter of 2012 compared with 35.5 percent for the same period in 2011. The lower effective tax rate for 2012 was primarily due to the completion of an analysis in the first quarter on the eligibility of certain expenses that qualified for an extended carryback beyond the typical two-year carryback period. As a result, Xcel Energy recognized a discrete tax benefit of approximately $15 million. Without this tax benefit, the effective tax rate for continuing operations for the first quarter of 2012 would have been 34.9 percent.

Factors Affecting Results of Operations

Fuel Supply and Costs

See the discussion of fuel supply and costs in Item 1 in Xcel Energy Inc.'s Annual Report on Form 10-K filed for the year ended Dec. 31, 2011.

Public Utility Regulation

NSP-Minnesota

NSP-Minnesota CapX2020 Certificate of Need (CON) — In 2009, the MPUC granted CONs to construct one 230 kilovolt (KV) electric transmission line and three 345 KV electric transmission lines as part of the CapX2020 project. The estimated cost of the four major transmission projects is $1.9 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total cost. The remainder of the costs will be born by other utilities in the upper Midwest. These cost estimates will be revised after the regulatory process is completed.

NSP-Minnesota and Great River Energy filed four route permit applications with the MPUC in addition to a facility permit application with the SDPUC, a certificate of corridor compatibility application with the NDPSC and a Certificate of Public Convenience and Necessity (CPCN) application with the PSCW. The MPUC has issued route permits for the Minnesota portion of the Fargo, N.D. to St. Cloud, Minn. project, the Brookings, S.D. project, and the Bemidji, Minn. to Grand Rapids, Minn. project. In April 2012, the MPUC approved the route permit for the portions of the new transmission lines between Hampton, Minn. and La Crosse, Wis. to be constructed in Minnesota. The remaining required permit activities are ongoing in North Dakota and Wisconsin.

In December 2011, the Monticello, Minn. to St. Cloud, Minn. project was placed in service and MISO granted the final approval of the Brookings, S.D. project as a multi-value project (MVP).

NSP-Wisconsin

NSP-Wisconsin CapX2020 CPCN — An application for a CPCN for the Wisconsin portion of the 345 KV CapX2020 project was filed with the PSCW in January 2011. This line is expected to entail construction of approximately 150 miles of new transmission lines between Hampton, Minn. and La Crosse, Wis. with approximately 50 miles located in Wisconsin at an estimated cost of $200 million to NSP-Wisconsin.

In June 2011, the PSCW determined the application was complete, which triggered the 360-day deadline for the PSCW to approve a CPCN for the project. Technical and public hearings were held in March 2012. PSCW Staff testimony supported the need for the project, both on a local and regional basis. The majority of the technical hearings covered issues regarding the various route alternatives. A PSCW final decision regarding the need and route locations is expected in June 2012.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — In July 2011, the FERC issued Order 1000 adopting new requirements for transmission planning, cost allocation, and development. On April 18, 2012, the Minnesota Governor signed legislation that preserves the rights of incumbent utilities to construct and own transmission interconnected to their systems. This legislation is similar to the legislation previously passed in North Dakota and South Dakota. Therefore, Order 1000 is expected to have very limited impacts on future transmission development and ownership in the NSP System in Minnesota, North Dakota, and the South Dakota. The impacts of the new requirements relating to future transmission development and ownership in Wisconsin are uncertain. Compliance filings to address these new requirements are due October 2012 and are effective prospectively. Motions for rehearing are pending action by the FERC.

La Crosse, Wis. to Madison, Wis. Transmission Line Complaint — In February 2012, Xcel Energy Inc. and NSP-Wisconsin filed a complaint with the FERC concerning ownership of the proposed La Crosse, Wis. to Madison, Wis. 345 KV transmission line. The complaint states that MISO has determined that the line is to be owned by Xcel Energy and American Transmission Company LLC (ATC) under the terms of the MISO Transmission Owners Agreement (TOA) and Tariff; however, ATC has a different interpretation of the tariff provisions that would effectively deny NSP-Wisconsin the ability to invest $175 million in the proposed MVP, which Xcel Energy Inc. and NSP-Wisconsin believe will lower the overall cost of the project. The complaint requests the FERC rule by June 2012 that ATC has not complied with the TOA and Tariff, which are subject to the FERC regulation. The timing and ultimate resolution of the complaint are unknown.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. See Note 14 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 for further discussion regarding the nuclear generating plants. Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level radioactive waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in the plant.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear plants. The event at the nuclear plant in Fukushima, Japan could impact the NRC's deliberations on NSP-Minnesota's power uprates discussed below. This event could also result in additional regulation by the NRC, which could require additional capital expenditures or operating expenses. The NRC has created an internal task force that has developed recommendations for NRC consideration on whether it should require immediate emergency preparedness and mitigating enhancements at U.S. reactors and any changes to NRC regulations, inspection procedures, and licensing processes. On July 12, 2011, the task force released its recommendations in a written report. The report confirms the safety of U.S. nuclear energy facilities and recommends actions to enhance U.S. nuclear plant readiness to safely manage severe events. To better coordinate response activities, the U.S. nuclear energy industry has created a steering committee made up of representatives from major electric sector organizations to integrate and coordinate the industry's ongoing responses.

In March 2012, the NRC issued three orders and a request for additional information to all licensees. The orders included requirements for mitigation strategies for beyond design basis external events, requirements with regard to reliable spent fuel instrumentation, and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The request for additional information included requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards, and to assess the emergency preparedness staffing and communications capabilities at each plant. The requirements were consistent with the approach proposed by the industry and is expected to result in NSP-Minnesota spending approximately $20 to $50 million to comply with the requirements at the Monticello and Prairie Island plants. NSP-Minnesota is evaluating the information requests and orders and expects to fully comply. Based on current refueling outage plans specific to each nuclear facility, the dates of the required compliance begin in the second quarter of 2015 with all units being fully compliant by December 2016. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position, or cash flows.

Nuclear Plant Power Uprates

Prairie Island Nuclear Extended Power Uprate — In 2009, the MPUC approved a CON for an extended power uprate of approximately 164 MW for Prairie Island Units 1 and 2. Recent analysis of the extended power uprate submittals to the NRC concluded that significant additional design work beyond NSP-Minnesota's estimated schedule and cost plan would be required for a successful application submittal. As a result, NSP-Minnesota completed an economic and new project design analysis and submitted a Change in Circumstances filing with the MPUC in March 2012. NSP-Minnesota asked the MPUC to confirm that the extended power uprate project is in the best interest of customers prior to NSP-Minnesota making the significant investments necessary to complete an application and undertake the NRC licensing process. The updated analysis shows the project continues to show system benefits, however the magnitude of the benefits is substantially lower than originally anticipated. An MPUC decision is expected in the first half of 2013.

Monticello Nuclear Plant Extended Power Uprate — In 2008, NSP-Minnesota filed for both state and federal approvals of an extended power uprate of approximately 71 MW for NSP-Minnesota's Monticello nuclear plant. The MPUC approved the CON for the extended power uprate in 2008. The filing was placed on hold by the NRC staff to address concerns raised by the Advisory Committee on Reactor Safeguards related to containment pressure associated with pump performance. NSP-Minnesota has been working with the industry and regulatory agencies to address this issue and expects to submit an update to the application for approval to the NRC in the fourth quarter of 2012, which could result in approval of the extended power uprate project by the NRC in the second quarter of 2013. NSP-Minnesota is planning to implement the equipment changes needed to support the Monticello life extension and power uprate projects in the planned spring 2013 refueling outage.

Environmental, Legal and Other Matters

See a discussion of environmental, legal and other matters in Note 6 to the consolidated financial statements.

Critical Accounting Policies and Estimates

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported even if the nature of the accounting policies applied have not changed. Item 7 **—** Management's Discussion and Analysis, in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011, includes a discussion of accounting policies and estimates that are most significant to the portrayal of Xcel Energy's financial condition and results, and that require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. As of March 31, 2012, there have been no material changes to policies set forth in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011.

Pending Accounting Changes

See a discussion of recently issued accounting pronouncements and pending accounting changes in Note 2 to the consolidated financial statements.

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss or gain that may occur as a result of changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 8 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to some credit and nonperformance risk.

Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the nuclear decommissioning fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

***Commodity Price Risk* —** Xcel Energy Inc.'s utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

***Short-Term Wholesale and Commodity Trading Risk* —** Xcel Energy Inc.'s utility subsidiaries conduct various short-term wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms were as follows:

	Three Months Ended March 31	
(Thousands of Dollars)	**2012**	**2011**
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 20,424	$ 20,249
Contracts realized or settled during the period	(3,261)	(1,668)
Commodity trading contract additions and changes during period	3,482	5,902
Fair value of commodity trading net contract assets outstanding at March 31	$ 20,645	$ 24,483

At March 31, 2012, the fair values by source for the commodity trading net asset balances were as follows:

	Futures/ Forwards					
(Thousands of Dollars)	**Source of Fair Value**	**Maturity Less Than 1 Year**	**Maturity 1 to 3 Years**	**Maturity 4 to 5 Years**	**Maturity Greater Than 5 Years**	**Total Futures/ Forwars Fair Value**
NSP-Minnesota	1	$ 4,878	$ 14,377	$ 366	$ -	$ 19,621
PSCo	1	471	553	-	-	1,024
		$ 5,349	$ 14,930	$ 366	$ -	$ 20,645

1 — Prices actively quoted or based on actively quoted prices.

At March 31, 2012, a 10 percent increase or decrease in market prices for commodity trading contracts would have an immaterial impact to pretax income from continuing operations.

Xcel Energy's short-term wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, including transactions that are not recorded at fair value, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Period Ended March 31	VaR Limit	Average	High	Low
2012	$ 0.43	$ 3.00	$ 0.20	$ 0.92	$ 0.06
2011	0.30	3.00	0.17	0.30	0.10

Interest Rate Risk — Xcel Energy is subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options. At March 31, 2012, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $475 million related to expected 2012 debt issuances.

At March 31, 2012, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $4.1 million annually. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

Xcel Energy also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At March 31, 2012, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore, fluctuations in equity prices or interest rates do not have an impact on earnings.

***Credit Risk* —** Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At March 31, 2012, a 10 percent increase in prices would have resulted in a decrease in credit exposure of $7.5 million, while a decrease of 10 percent in prices would have resulted in an increase in credit exposure of $7.9 million.

Xcel Energy Inc. and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and generally requires that the most observable inputs available be used for fair value measurements. See Note 8 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at March 31, 2012. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues when necessary. Credit risk adjustments for other commodity derivative instruments are deferred as OCI or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at March 31, 2012.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs and forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent immaterial percentages of total assets and liabilities measured at fair value at March 31, 2012.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $5.9 million and $0.6 million of estimated fair values, respectively, for FTRs held at March 31, 2012.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were no Level 3 commodity forwards or options held at March 31, 2012.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities, private equity investments and real estate investments. To the extent appropriate, observable active market inputs are utilized to estimate the fair value of asset-backed and mortgage-backed securities. However, less observable and subjective inputs that may be used in conjunction with available pricing of similar securities in active markets can be significant to these valuations. These inputs include estimated principal prepayments and risk-based adjustments to the interest rate used to discount expected future cash flows in a discounted cash flow model. Given the potential significant impacts that unobservable inputs may have on the valuations of asset-backed and mortgage-backed securities, and based on an evaluation of NSP-Minnesota's ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling $133.2 million in the nuclear decommissioning fund at March 31, 2012 (approximately 9.0 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

Liquidity and Capital Resources

Cash Flows

	Three Months Ended March 31	
(Millions of Dollars)	**2012**	**2011**
Cash provided by operating activities	$ 477	$ 659

Net cash provided by operating activities decreased by $182 million for the three months ended March 31, 2012, compared with the three months ended March 31, 2011. The decrease was primarily related to lower net income, higher pension contributions and the effect of the income taxes paid in 2012 compared to the refund received in 2011.

	Three Months Ended March 31	
(Millions of Dollars)	**2012**	**2011**
Cash used in investing activities	$ (399)	$ (624)

Net cash used in investing activities decreased by $225 million for the three months ended March 31, 2012, compared with the three months ended March 31, 2011 The decrease was due, in part, to progress payments made in 2011 for the Merricourt wind project, higher 2011 capital expenditures, primarily related to amounts associated with the Jones Plant site in Lubbock, Texas, as well as timing of payments, and the change in restricted cash due to customer refunds associated with the nuclear waste disposal settlement with the U.S. Department of Energy.

	Three Months Ended March 31	
(Millions of Dollars)	**2012**	**2011**
Cash used in financing activities	$ (39)	$ (49)

Net cash used in financing activities decreased by $10 million for the three months ended March 31, 2012, compared with the three months ended March 31, 2011. The decrease was primarily due to higher proceeds from short-term borrowings, partially offset by repurchases of common stock and higher dividend payments.

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Regulation of Derivatives **—** In July 2010, financial reform legislation was passed, which provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the Commodity Futures Trading Commission (CFTC) and SEC with expanded regulatory authority over derivative and swap transactions. Regulations effected under this legislation could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could negatively impact the market for these transactions or result in extensive margin and fee requirements. Additionally there may be material increased reporting requirements. The bill contains provisions that should exempt certain derivatives end users from much of the clearing and margining requirements. However, the CFTC is still developing the regulatory rules under the act and, it is not clear whether Xcel Energy will qualify for the exemption. In addition, although the CFTC's proposed rules would extend the end user exemption to margin requirements, they would impose a requirement to have credit support agreements in their place. If Xcel Energy does not meet the end user exception, the margin requirements could be significant. The full implications for Xcel Energy can not yet be determined until the various definitions and rulemakings are completed.

FERC Order 741 addresses rulemaking addressing the credit policies of organized electric markets and limits the amount of overall credit available to entities operating and places restrictions on netting of transactions within organized markets unless certain market protocols are implemented by the Regional Transmission Organization (RTO). The various RTOs are in the process of filing their proposed market protocols to satisfy FERC Order 741 and these new market designs may lead to additional margin requirements that could impact our liquidity.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short–term to long-duration fixed income securities, and alternative investments, including private equity, real estate and commodity index investments. In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans. In 2011, contributions of $137.3 million were made across three of Xcel Energy's pension plans. For future years, we anticipate contributions will be made as necessary.

Capital Sources

Short-Term Funding Sources **—** Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments **—** Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At March, 31, 2012, approximately $3.3 million of cash was held in these liquid operating accounts.

Commercial Paper **—** Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $800 million for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $300 million for SPS; and
- $150 million for NSP-Wisconsin.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2012	Twelve Months Ended Dec. 31, 2011
Borrowing limit	$ 2,450	$ 2,450
Amount outstanding at period end	339	219
Average amount outstanding	324	430
Maximum amount outstanding	463	824
Weighted average interest rate, computed on a daily basis	0.36%	0.36%
Weighted average interest rate at period end	0.36	0.40

Credit Facilities — During March of 2011, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. executed 4-year credit agreements. The total capacity of the credit facilities increased approximately $273 million to $2.45 billion. As of April 23, 2012, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Facility (a)	Drawn (b)	Available	Cash	Liquidity
Xcel Energy Inc.	$ 800.0	$ 227.0	$ 573.0	$ 1.0	$ 574.0
PSCo	700.0	3.0	697.0	0.2	697.2
NSP-Minnesota	500.0	22.7	477.3	1.1	478.4
SPS	300.0	53.0	247.0	1.1	248.1
NSP-Wisconsin	150.0	80.0	70.0	0.7	70.7
Total	$ 2,450.0	$ 385.7	$ 2,064.3	$ 4.1	$ 2,068.4

(a) These credit facilities expire in March 2015.

(b) Includes outstanding commercial paper and letters of credit.

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated during consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

Financing Plans — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund construction programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- NSP-Minnesota may issue approximately $800 million of first mortgage bonds in the third quarter of 2012.
- PSCo may issue approximately $750 million of first mortgage bonds in the third quarter of 2012.
- SPS may issue approximately $100 million of first mortgage bonds in the first half of 2012.
- NSP-Wisconsin may issue approximately $100 million of first mortgage bonds in the second half of 2012.

Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Earnings Guidance

Xcel Energy's 2012 earnings is expected to be in the lower half of the guidance range of $1.75 to $1.85 per share. Key assumptions related to earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings, including the MPUC's approval of our request to defer incremental property tax increases in 2012.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-adjusted retail electric utility sales are projected to be relatively flat.
- Weather-adjusted retail firm natural gas sales are projected to be relatively flat.
- Rider revenue recovery is projected to increase approximately $35 million to $45 million over 2011 levels.
- O&M expenses are projected to increase up to 1.0 percent over 2011 levels.
- Depreciation expense is projected to increase $50 million to $60 million over 2011 levels.
- Property taxes are projected to be relatively flat. This assumes the MPUC approves NSP-Minnesota's request to defer incremental 2012 property taxes in Minnesota.
- Interest expense (net of AFUDC — debt) is projected to increase approximately $10 million.
- AFUDC — equity is projected to increase approximately $10 million to $20 million over 2011 levels.
- The effective tax rate is projected to be approximately 34 percent to 35 percent.
- Average common stock and equivalents are projected to be approximately 488 million shares.

Item 3 — QUANTITATIVE ANDQUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis under Item 2.

Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of March 31, 2012, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy's internal control over financial reporting.

Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy. Xcel Energy has recorded an estimate of the probable cost of settlement or other disposition for such matters.

Additional Information

See Note 6 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Note 5 to the consolidated financial statements for discussion of proceedings involving utility rates and other regulatory matters.

Item 1A — RISK FACTORS

Xcel Energy Inc.'s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2011, which is incorporated herein by reference.

Item 2 — UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

	Issuer Purchases of Equity Securities			
Period	**Total Number of Shares Purchased**	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Nu Approximate Value) of Sha May Yet Be Pu Under the P Program**
Jan. 1, 2012 — Jan. 31, 2012 (a)	17,487	$ 26.69	-	
Feb. 1, 2012 — Feb. 29, 2012	-	-	-	
March 1, 2012 — March 31, 2012 (b)	700,000	26.42	-	
Total	717,487		-	

(a) Xcel Energy Inc. or one of its agents periodically purchases common shares in order to satisfy obligations under the Stock Equivalent Plan for Non-Employee Directors.

(b) The Xcel Energy Inc. Board of Directors approved the repurchase of up to 700,000 shares of common stock for the issuance of shares in connection with the vesting of awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan. Purchases were authorized to be made in the open market pursuant to Rule 10b-18.

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

In June 2011, the FASB issued *Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05).* On Jan. 1, 2012, Xcel Energy implemented the requirements of ASU No. 2011-05 by presenting net income, the components of OCI and total comprehensive income in two separate, but consecutive financial statements of net income and comprehensive income. The implementation resulted in more prominent presentation of total comprehensive income and more detailed presentation of the components of OCI.

The following presents retrospective application of ASU No. 2011-05 to the consolidated financial statements of Xcel Energy Inc. and subsidiaries, as a separate but consecutive statement following Xcel Energy Inc. and subsidiaries' consolidated statements of income for the years ended Dec. 31, 2011, 2010 and 2009. The financial statement presentation requirements of ASU No. 2011-05 do not affect the items previously reported in net income, OCI or total comprehensive income, or the guidance for reclassifying components of OCI to net income, and therefore retrospective application of the new guidance does not result in significant changes to the information reported in the previously issued financial statements.

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended Dec. 31		
(Thousands of Dollars)	**2011**	**2010**	**2009**
Net income	$841,172	$755,834	$680,887
Other comprehensive (loss) income			
Pension and retiree medical benefits:			
Net pension and retiree medical benefit losses arising during the period, net of tax of $(4,442), $(2,647) and $(3,215), respectively	(6,367)	(3,606)	(4,604)
Amortization of losses included in net periodic benefit cost, net of tax of $2,195, $1,231 and $1,012, respectively	3,162	1,751	1,475
	(3,205)	(1,855)	(3,129)
Derivative instruments:			
Net fair value decrease, net of tax of $(25,086), $(3,159) and $(843), respectively	(38,292)	(4,289)	(710)
Reclassification of losses to net income, net of tax of $598, $1,951 and $5,067, respectively	648	2,630	7,388
	(37,644)	(1,659)	6,678
Marketable securities:			
Net fair value (decrease) increase, net of tax of $(63), $89 and $284, respectively	(93)	130	411
Other comprehensive (loss) income	(40,942)	(3,384)	3,960
Comprehensive income	$800,230	$752,450	$684,847

Xcel Energy also files condensed financial statements of the parent company, Xcel Energy Inc., in its Form 10-K as Schedule I. The statements of comprehensive income above presenting retroactive application of ASU No. 2011-04 to Xcel Energy Inc. and subsidiaries are identical to those of the parent company.

Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 20, 2011 (Exhibit 3.01 to Form 8-K of Xcel Energy file number 001-03034, dated May 18, 2011).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

April 27, 2012

By: /s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Vice President and Controller
(Principal Accounting Officer)

/s/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 31.01

CERTIFICATION

I, Benjamin G.S. Fowke III, certify that:

1. I have reviewed this report on Form 10-Q of Xcel Energy Inc. (a Minnesota corporation);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 27, 2012

/s/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Chairman, President, Chief Executive Officer and Director

Exhibit 31.02

CERTIFICATION

I, Teresa S. Madden, certify that:

1. I have reviewed this report on Form 10-Q of Xcel Energy Inc. (a Minnesota corporation);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 27, 2012

/s/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer

Exhibit 32.01

OFFICER CERTIFICATION

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Xcel Energy Inc. (Xcel Energy) on Form 10-Q for the quarter ended March 31, 2012, as filed with the SEC on the date hereof (Form 10-Q), each of the undersigned officers of Xcel Energy certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Xcel Energy as of the dates and for the periods expressed in the Form 10-Q.

Date: April 27, 2012

/s/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Chairman, President, Chief Executive Officer and Director

/s/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Xcel Energy and will be retained by Xcel Energy and furnished to the SEC or its staff upon request.

Exhibit 99.01

XCEL ENERGY CAUTIONARY FACTORS

The Private Securities Litigation Reform Act provides a “safe harbor” for forward-looking statements to encourage disclosures without the threat of litigation, providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements are made in written documents and oral presentations of Xcel Energy Inc. or any of its subsidiaries. These statements are based on management’s beliefs as well as assumptions and information currently available to management. Such forward-looking statements are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should” and similar expressions. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause Xcel Energy’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures;
- The risk of a significant slowdown in growth or decline in the U.S. economy, the risk of delay in growth recovery in the U.S. economy or the risk of increased cost for insurance premiums, security and other items as a consequence of past or future terrorist attacks;
- Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where Xcel Energy has a financial interest;
- Customer business conditions, including demand for their products or services and supply of labor and materials used in creating their products and services;
- Financial or regulatory accounting principles or policies imposed by the FASB, the SEC, the FERC and similar entities with regulatory oversight;
- Availability or cost of capital such as changes in: interest rates; market perceptions of the utility industry, Xcel Energy Inc. or any of its subsidiaries; or security ratings;
- Factors affecting utility and nonutility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel, nuclear fuel or natural gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; nuclear or environmental incidents; cyber incidents; or electric transmission or natural gas pipeline constraints;
- Employee workforce factors, including loss or retirement of key executives, collective bargaining agreements with union employees, or work stoppages;
- Increased competition in the utility industry or additional competition in the markets served by Xcel Energy Inc. and its subsidiaries;
- State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric and natural gas markets; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Environmental laws and regulations, including legislation and regulations relating to climate change, and the associated cost of compliance;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities, which are values established by regulators assigning environmental costs to each method of electricity generation when evaluating generation resource options;
- Nuclear regulatory policies and procedures, including operating regulations and spent nuclear fuel storage;
- Social attitudes regarding the utility and power industries;
- Cost and other effects of legal and administrative proceedings, settlements, investigations and claims;
- Technological developments that result in competitive disadvantages and create the potential for impairment of existing assets;
- Risks associated with implementations of new technologies; and
- Other business or investment considerations that may be disclosed from time to time in Xcel Energy Inc.’s SEC filings, including “Risk Factors” in Item 1A of Xcel Energy’s Form 10-K for the year ended Dec. 31, 2011, or in other publicly disseminated written documents.

Xcel Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exhaustive.