Scott A. Thomson
Vice President, Regulatory Affairs and
Chief Financial Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 443-6565
Fax: (604) 443-6534
Email: scott.thomson@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

August 13, 2009

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("TGI", the "Company"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW")
Collectively the "Terasen Utilities"
Return on Equity and Capital Structure Application (the "Application")

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 2

On May 15, 2009, the Terasen Utilities filed the Application as referenced above. In accordance with Commission Order No. G-70-09 setting out the Regulatory Timetable for the Application, the Terasen Utilities respectfully submit the attached response to BCUC IR No. 2, in advance of the August 14, 2009 deadline.

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

Sincerely,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed by:

Scott A. Thomson
Vice President, Regulatory Affairs & CFO

Attachments

cc (email only): Registered Parties

90.0 Reference: Business Risk – Financing Ability

Exhibit B-3, BCUC IRs 1.3, 3.2, 47.1

"The "changed circumstances" articulated in the Application relate both to changes in risk and to recent events in the financial and credit markets." Ref: Response to Exhibit B-3, BCUC IR 1.3

TGI issued debt in	Sept 2006	Oct 2007	June 2008	Feb 2009
	5.55%	6.00%	5.80%	6.55%

90.1 What is Terasen's view of the magnitude of the "recent events in the financial and credit markets"? Has this been the greatest disruption to the financial and credit markets in the history of Terasen Gas?

Response:

The rapidity and magnitude of the decline of corporate credit markets and domestic and international stock markets has been very significant. Corporate utility spreads more than doubled in the August 2008 to January 2009 period to approximately 400 basis points, whereas the equity markets had a similar significant risk repricing, experiencing an approximate 41% decline over that time period.

It is not possible to definitively state whether the recent market events are the greatest disruption the company has witnessed. In the history of Terasen Gas, there have been major disruptions in financial and credit markets, such as during the recession in 1982/83, the recession in 1991/92, following the bail out of Long Term Capital Management in 1998 and during the collapse of the tech bubble during 2001/02. What has marked this disruption is the speed and magnitude of the change in market conditions and the fact that the adverse conditions have not been limited to any one sector.

As global financial and credit markets become more integrated, the frequency of the disruptions appears to be increasing and, given the many linkages between issuers, commercial/investment banks, institutional debt lenders and equity investors, disruptions today are more likely to cascade through the financial system causing greater potential damage, which is more widespread.

90.2 Terasen was able to refinance debt in February 2009 at rates not unlike October 2007. What does this indicate of the market's perception of Terasen's business risk?

Response:

The February Terasen issue resulted in a credit spread of 2.85% and a coupon of 6.55%. The October 2007 issue had a credit spread of 1.48% and a coupon of 6.00%. The coupon in 2009 was approximately 9% higher, while the spread was almost double that of 2007. With respect to credit investors, the perception of risk was higher in 2009 than 2007.

90.3 Have other Canadian Utilities been able to refinance debt at rates similar to their historical rates in the same manner as Terasen?

Response:

As noted in response to BCUC IR#2 90.2 above, the 2009 debt issue had a coupon that was approximately 9% higher and a credit spread almost double that of 2007. From this perspective, Terasen is of the view that the issuance rates in early 2009 were not similar to historical rates. Terasen is of the view that other similarly rated issuers as Terasen would have experienced a similar market spread and coupon differential from previous periods.

90.4 Please describe the Canadian debt market, in and around the February 2009 time frame, from the perspective of corporate bond issuers. Who was able to able to issue debt and who was not able to issue debt? Please elaborate.

Response:

While the Canadian capital markets had experienced a significant period of turmoil commencing in 2007, the current financial market crisis commenced in earnest in September of 2008 and peaked early 2009. Corporate spreads had peaked in January 2009 and had started to ease during February. During the months preceding February 2009, corporate bond issuers faced significantly reduced demand for longer term debt as certain issuers where restricted to maturities in the 3 to 5 year term. While Terasen does not know who was not able to issue, based on anecdotal discussions with investment bankers, issuance was restricted to stronger rated corporate issuers and term was limited. The table which follows is provided by Scotia Capital and demonstrates the issuance in the utility and infrastructure space between August 2008 and February 2009.

Isssue Date	Issuer	Amt	Coupon	Maturity	Spread	DBRS	S&P	Moody's
26-Aug-08	Union Gas	$300.00 M	6.05%	2-Sep-38	200	A	BBB+	
8-Oct-08	Gaz Metro Inc.	$150.00 M	5.40%	15-Apr-13	260	A	A	
5-Nov-08	Hydro One	$400.00 M	5.00%	12-Nov-13	210	A(H)	A+	Aa3
6-Nov-08	Enbridge Gas Distribution Inc	$200.00 M	5.57%	29-Jan-14	265	A	A-	
13-Nov-08	Enbridge Pipelines Inc	$300.00 M	6.62%	19-Nov-18	285	A(H)	A-	
14-Nov-08	Hydro One	$100.00 M	3.89%	19-Nov-10	197.5	A(H)	A+	Aa3
3-Dec-08	GTAA	$325.00 M	5.89%	6-Dec-13	350	A	A	A2
9-Dec-08	Nova Scotia Power	$150.00 M	5.75%	1-Oct-13	400	A(L)	BBB	Baa1
16-Dec-08	British Columbia Ferries Services	$140.00 M	6.12%	19-Dec-13	400	A(L)	A-	
8-Jan-09	Hydro One	$100.00 M	3.89%	19-Nov-10	230	A(H)	A+	Aa3
9-Jan-09	Hydro One	$200.00 M	5.00%	12-Nov-13	250	A(H)	A+	Aa3
15-Jan-09	407 International Inc.	$300.00 M	4.65%	20-Jan-12	340	A	A	
15-Jan-09	407 International Inc.	$200.00 M	5.10%	20-Jan-14	345	A	A	
15-Jan-09	Nova Scotia Power	$50.00 M	5.75%	1-Oct-13	390	A(L)	BBB	Baa1
30-Jan-09	Brookfield Renewable Power Inc.	$300.00 M	8.75%	3-Feb-12	694.9	BBB(H)	BBB	
10-Feb-09	FortisAlberta	$100.00 M	7.06%	14-Feb-39	320	A(L)	A-	Baa1
11-Feb-09	TransCanada Pipelines	$300.00 M	5.05%	14-Feb-14	305	A	A-	A3
11-Feb-09	TransCanada Pipelines	$400.00 M	8.05%	17-Feb-39	430	A	A-	A3
19-Feb-09	Terasen Gas	$100.00 M	6.55%	24-Feb-39	285	A		A3
26-Feb-09	Hydro One	$300.00 M	6.03%	3-Mar-39	232	A(H)	A+	Aa3

91.0 Reference: ROE Data – Missing Table

Exhibit B-3, BCUC IR 3.3

91.1 Please indicate the location of the table answering Exhibit B-3, BCUC IR 3.3. Is this the table on page 42?

Response:

Below is the table inadvertently omitted from the response to BCUC IR 1.3.3.

Line No.	Years	ROE Allowed	ROE Achieved Pre-Earnings Sharing	ROE Achieved Post-Earnings Sharing	Incentives Earned ($000)
	(1)	(2)	(3)	(4)	(5)
1	12/31/1992	12.25%	9.060%	N / A	N / A
2					
3	12/31/1993	N / A	11.909%	N / A	N / A
4					
5	12/31/1994	10.65%	9.727%	N / A	N / A
6					
7	12/31/1995	12.00%	12.030%	N / A	N / A
8					
9	12/31/1996	11.00%	11.803%	N / A	N / A
10					
11	12/31/1997	10.25%	11.266%	N / A	N / A
12					
13	12/31/1998	10.00%	9.405%	9.703%	$ (1,531)
14					
15	12/31/1999	9.25%	10.698%	9.974%	$ 3,860
16					
17	12/31/2000	9.50%	10.748%	10.124%	$ 3,470
18					
19	12/31/2001	9.25%	9.375%	9.313%	$ 456
20					
21	12/31/2002	9.13%	9.729%	N / A	N / A
22					
23	12/31/2003	9.42%	10.226%	N / A	N / A
24					
25	12/31/2004	9.15%	9.344%	9.247%	$ 1,179
26					
27	12/31/2005	9.03%	10.784%	9.907%	$ 6,969
28					
29	12/31/2006	8.80%	10.472%	9.636%	$ 7,147
30					
31	12/31/2007	8.37%	10.729%	9.550%	$ 10,018
32					
33	12/31/2008	8.62%	10.637%	9.628%	$ 8,726
34					
35	Notes:				
36	1992 includes Fort Nelson Service Area.				
37	Incentives Earned are after-tax				

91.2 Please detail the incentives earned that result in the Achieved Pre-Earnings Sharing ROE.

Response:

Please refer to the response to BCUC IR 2.91.1.

92.0 Reference: Special Direction – OIC 1510

Exhibit B-3, BCUC IR 4.1

92.1 Please outline Terasen’s understanding of Clause 1.3 of the Special Direction which delineates when the Special Direction will expire. Specifically, when will the “Squamish Gas Transportation Service Agreement” terminate?

Response:

The Squamish Gas Transportation Service Agreement was amended in the Squamish Gas Arrangements Termination Agreement between Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Squamish) Inc. and the Province of British Columbia, dated October 5, 2006. The Squamish Gas Arrangements Termination Agreement provides, in Paragraph 2.4 (c) that the term of the Squamish Gas Transportation Service Agreement “shall continue until the later of (i) the date upon which the balance of the RDDA of TGVI has been reduced to zero, and (ii) the date upon which the Commission establishes a new rate for the transportation of Gas to Shipper.” The “Shipper” is Terasen Gas Inc. for gas delivered to Squamish.

A copy of the Squamish Gas Arrangements Termination Agreement is included in Attachment 92.1.

93.0 Reference: TQM Decision

Application, Cover Letter, p. 5, par. 2, line 3

Exhibit B-3, BCUC IR 5.0

93.1 Please indicate how the 300 basis points increase was calculated.

Response:

ATWACC	6.40%
Before tax WACC = (ATWACC/(1-t))	9.41%
Deduct interest at TQM:	
Cost of Debt = 6.07% on 70% of capital structure	4.25%
Pre-tax Return = BTWACC - Interest	5.16%
Tax at 32%	1.65%
Equity Return	
Pre-tax Return minus tax	3.51%
ROE at 30% equity	11.70%
2008 Formula ROE	8.71%
Difference	2.99%

93.2 What would be Terasen's imputed ROE using the TQM Decision's "weighted after tax average cost of capital of 6.4%"? Please show the calculations.

Response:

As noted in response to BCUC 1.5.5, TGI is not requesting an ATWACC approach. Further, as noted in that response, even if the BCUC were to adopt an ATWACC approach, TGI does not believe that it should be at risk for the difference between the embedded cost of debt that it has

incurred under the existing methodology and the current cost of debt as each of the debt issues and their costs have previously been approved by the BCUC under the Utilities Commission Act. If ATWACC were adopted and TGI were allowed to recover its embedded cost of debt, the NEB's ATWACC would need to be adjusted for the difference between TGI's embedded debt cost (6.64%) and the market debt cost used by the NEB to develop the 6.4% ATWACC. Footnote 36 of the TQM decision suggests that the market cost of debt used by the NEB may have been 5.5%.

The adjusted (for the difference between market and embedded cost of debt) ATWACC using values for 2009 is estimated as follows:

Rate Base ($MM)	**Debt Ratio**	**Debt ($)**	**Embedded Cost of Debt**	**Interest Expense**
(1)	(2)	(3) = (1) X (2)	(4)	(5) = (3) X (4)
$2412	60%	$1447.2	6.64%	$96.09

Embedded Cost of Debt:	6.64%
Market Cost of Debt:	5.50%
Difference:	1.14%
After-tax Difference (at 2009 tax rate of 30.5%):	0.79%
Additional After-tax Interest Expense (Debt X after-tax difference): $1447.2 X 0.79%	$11.43
Adjustment to ATWACC:	
Additional After-tax Interest Expense Divided by Total Rate Base: $11.43/$2412	0.47%

Original ATWACC:	6.40%
Add differential for interest:	0.47%
Adjusted ATWACC:	6.87%
Before-Tax WACC (ATWACC/(1-t))	9.89%
Deduct interest at embedded cost of debt (6.64%) at 60% debt	3.98%
Pre-tax Return	5.91%
Tax at 30.5%	1.80%
Equity Return	
Pre-tax Return minus tax	4.11%
ROE at 40% equity	10.26%

94.0 Reference: Credit Rating

Exhibit B-3, BCUC IR 8.1

94.1 Does Terasen see a specific link between the Allowed ROE, Equity component, and Credit Rating?

Response:

There is no specific or explicit quantitative link between allowed ROE, equity component and credit rating, in part because credit ratings are not determined formulaically. As a general proposition, the higher the business and regulatory risk a utility faces, the stronger the credit metrics will have to be to achieve a given credit rating. Since credit metrics are a function of the combination of capital structure and ROE, the higher the utility’s business risk, the higher the combined equity component and ROE will have to be to achieve a given credit rating. There are trade-offs between the capital structure and ROE: utilities with the same business risk can achieve similar credit metrics (and thus similar credit ratings) with different combinations of ROE and capital structure.

94.2 Does this specific link affect all Natural Gas Utilities equally?

Response:

Please see response to BCUC IR 2.94.1.

95.0 Reference: ROE Allowed and Achieved

Exhibit B-3, BCUC IR 12.1

95.1 From the response provided to Exhibit B-3, BCUC IR 12.1, Terasen has achieved greater ROE than approved every year since 1999. For each year explain how the achieved ROE differed from the approved ROE, such as arising from O&M savings, capital gains on disposal, or load variances.

Response:

Please refer to the table which breaks down the components of the difference between the allowed and achieved ROE for each year. Please note that for 2004, the achieved ROE was reported in IR 1.12.1 as 9.344% when it should have been 9.460%. The achieved post-sharing ROE would therefore be 9.305% instead of 9.247% as reported.

	1999	2000	2001	2004	2005	2006	2007	2008
O&M Savings	0.66%	0.52%	0.13%	0.51%	1.59%	1.32%	1.55%	1.08%
Depreciation Savings	0.04%	0.00%	0.06%	0.22%	0.45%	0.40%	1.12%	1.07%
Tax shield on CCA	-0.09%	0.04%	-0.12%	-0.05%	-0.16%	-0.16%	-0.23%	-0.25%
Gross Margin	0.42%	0.20%	-0.33%	-0.18%	0.05%	-0.15%	-0.20%	0.03%
Other Revenue	0.20%	0.22%	0.15%	-0.22%	-0.23%	-0.17%	-0.23%	-0.15%
Return on Avoided Rate Base	0.28%	0.22%	0.25%	-0.05%	-0.09%	0.45%	0.34%	0.23%
Other - mainly income tax timing differences	-0.06%	0.05%	-0.01%	0.08%	0.14%	-0.02%	0.00%	0.01%
Achieved vs. Allowed ROE	**1.45%**	**1.25%**	**0.13%**	**0.31%**	**1.75%**	**1.67%**	**2.36%**	**2.02%**
TGI's 50% Share of ROE Variance	**0.72%**	**0.62%**	**0.06%**	**0.16%**	**0.88%**	**0.84%**	**1.18%**	**1.01%**

96.0 Reference: TGVI Royalty Subsidy

Exhibit B-3, BCUC IR 17.1

96.1 Please further explain the last sentence of 17.2.1 which states that "The Royalty subsidy will be removed by the end of 2011 at which time there will be substantial upward pressure on rates which would be expected to exceed those of the BC Hydro RIB rates."

Response:

Terasen would like to clarify that the sentence should have said "BC Hydro average rate" not the "BC Hydro RIB rates".

With the recent establishment of the BC Hydro RIB structure the actual operating cost difference between a natural gas home and an electricity home with the same applications has been complicated. To determine this operating cost difference one would need to look at the specific use pattern of the dwelling related to its total natural gas consumption and superimpose this on their existing electricity use to determine the appropriate electrical rate to use in the comparison. Terasen Gas would agree that in most cases for single family homes the BC Hydro RIB Step 2 rate is a reasonable comparison for space heating applications. The RIB Step 2 rate, however, is not necessarily a good comparison for the space heating requirements of a townhouse, condo or apartment. Much of the space heating energy consumption from these types of dwellings may come from the RIB Step 1 rate.

Given this backdrop, as outlined in the table below, the loss of the royalty subsidy on TGVI cost of gas will be about $3.00 Cdn/GJ with its expiry at the end of 2011, based on the numbers in the table below for an estimate.

	2007 Approved	2008 Approved	2009 Projected	2010 Forecast	2011 Forecast	Average 2007-2011
Royalty Credits (000's)	$ 35,063	$ 43,142	$ 28,095	$ 35,832	$ 40,091	$ 36,445
Sales Volumes (TJs)	12,295	12,671	12,264	12,241	12,433	12,381

Impact of Loss of Royalty $2.94

When looking at this gas cost increase due to the loss of the Royalty subsidy on TGVI, the statement contained in the preamble "which would be expected to exceed those of the BC Hydro RIB rates," must be viewed with how the RIB decision impacts the Step 1 and Step 2 rate. In principle, the RIB represents a splitting of the allocated historical costs for the residential class into two rate blocks, with the rate for the second step being higher, in order to promote energy conservation. Notwithstanding this design, the conservation impact is significantly dampened given the constraint of revenue neutrality for the residential class, meaning that the higher RIB Step 2 rate revenues serve to reduce the rate applying to the Step 1 rate. Therefore, in the table below, the average BC Hydro rate increase is displayed.

April 1, 2009

***Calculated BC Hydro Rate**

Rate Schedule 1101 Residential	Weighted Average BC Hydro Rate based on a 8.74% increase to Apr. 1/08 rates (Inclusive of Deferral Account Rate Riders of 0.5% and 1%)	Per GJ	At 90%	At 75%
Rate per kWh	$0.0691	$19.195	$17.275	$14.396

Forecast - April 1, 2010

****Calculated BC Hydro Rate**

Rate Schedule 1101 Residential		Per GJ	At 90%	At 75%
Rate per kWh	$0.0753	$20.917	$18.825	$15.688

*Calculated by adding 8.74% to the April 1, 2008 BCUC Approved BC Hydro residential rate inclusive of the applicable Deferral Account Rate Riders
**Calculated by adding 9% to the calculated April 1, 2009 BC Hydro residential rate

In both cases (at 90% and 75% levels of efficiency) the loss of the TGVI royalty exceeds the average increase to the BC Hydro average rate.

97.0 Reference: Business Risk – Capture rate of multi-family dwellings

Exhibit B-3, BCUC IRs 23.2.1, 37.1

97.1 Please confirm the 18% capture rate for multiple unit construction is with respect to the space heating for dwelling space.

Response:

The estimated capture rate of 18% for multi-family dwellings is with respect to the number of units that use natural gas for any purpose, not just for space heating.

97.2 Please provide the capture rate of multi-family dwellings that use natural gas for any purpose: heating of common space, cooking, and/or fireplaces.

Response:

See the response to BCUC IR 2.97.1.

97.3 Please confirm the validity of the Terasen assumption, used in the response to Exhibit B-3, BCUC IR 23.2.1, that in a ten block sample, not one of the resulting ten multi-unit complexes would use natural gas for space heating.

Response:

In TGI's response to BCUC IR1.23.2.1, the multi-family dwellings annual use per customer assumption of 59 GJ per year **does** include space heating loads. As per TGI's response to BCUC IR1.23.2.1.1, the estimated annual use per customer rate for multi-family dwellings (such as the one's described above) is 23 GJ per year. TGI would classify these types of buildings as vertical subdivisions, and estimates the space heating requirements to be approximately 36 GJ per year, per unit.

98.0 Reference: Furnace Life

Exhibit B-3, BCUC IR 35.1

Exhibit B-4, CEC IR 21.5

98.1 Please reconcile the maximum furnace life of 30 years with the average life of 18 years used in the cost comparison calculations.

Response:

Maximum furnace life was used in the responses referenced above to address the time period over which it could be expected that more rigourous standards in minimum efficiency levels would impact average use rate. CEC IR 1.21.5 asked *"When does Terasen expect the average use rate to bottom out?"* The response stated that it would not be unreasonable to expect that major impacts from increased minimum efficiency standards would cease concurrent with estimated maximum appliance life.

Terasen uses an average furnace appliance life of 18 years for energy efficiency planning and and analysis purposes. This more conservative figure is commonly used by utilities for energy efficiency planning and analysis purposes. For example, an effective measure life of 18 years was put forth by Navigant Consulting to the Ontario Energy Board in a recent proceeding.[1] Although the maximum service lives for some furnaces reach 30 years, it is not realistic to assume all new furnaces will reach the maximum service life. Therefore 18 years is used by Terasen as the average service life of a furnace.

98.2 What are the "current grant or rebates that a developer may receive"?

Response:

At the time of writing, Terasen is not aware of any grants or rebates for furnaces for residential new construction.

[1] Navigant Consulting, "Measures and Assumptions for Demand Side Management Planning", submission to Ontario Energy Board, April 16 2009, Appendix B, p. 15

99.0 Reference: Business Risk – Debt Issues

Exhibit B-3, BCUC IR 44.1

99.1 Please confirm Terasen has seen the lowest percentage increase, from 2006 to 2009, of the comparables provided.

Response:

Mr. Carmichael confirms the calculation, but also notes that Terasen went through a change of ownership commencing in February 2007.

99.2 Does this indicate the financial and credit markets view Terasen as the lowest risk?

Response:

No. Terasen’s credit spread falls between Enbridge Gas (rated A/A-), and Union Gas (rated A/BBB+). Mr. Carmichael would expect that the company viewed to have the lowest risk would also have the lowest credit spread above Government of Canada bonds, and Terasen Gas does not.

100.0 Reference: Business Risk – Financing

Exhibit B-3, BCUC IRs 47.1, 53.1

100.1 Do the current spreads indicate a return to "normality" in the financial and credit markets?

Response:

While credit spreads have decreased from the higher levels experienced in recent months, Terasen does not view that the markets have returned to normal. The global economy is still in recession and there continues to be volatility in both credit and equity markets. While recently there has been an improvement in overall market tone, there is no assurance that this improvement will continue as there is continued volatility which could result in a reversal in both financial and credit markets.

100.2 The charts seem to indicate that the period from September 2008 through June 2009 was an aberration due to the US induced credit crisis. Why shouldn't this data be discarded as being irrelevant to setting a forward-looking ROE and Capital Structure?

Response:

While the degree of volatility and the speed with which markets have deteriorated has marked this financial crisis as unique, it is not irrelevant as it has clearly demonstrated that the automatic adjustment mechanism that Terasen is currently operating under is flawed, and the matters referenced in the question are therefore quite relevant to the request to abandon the formula.

It follows from the observation in the question that "the period from September through June was an aberration" in financial markets that a formula that sets allowed returns on equity through the use of one component in those aberrant market conditions (long Canada yields) cannot result in a fair allowed return.

101.0 Reference: BCH Conservation Review – Fuel Switching

Exhibit B-4, CEC IR 34.1

101.1 Is it appropriate to reference the November 20, 2007 BC Hydro Conservation Review determination on fuel switching since the introduction by BC Hydro of the Tier 2 rate structure?

Response:

Yes.

It is relevant to use the BC Hydro 2007 CPR conclusion on fuel switching due to the nature of how this report has influenced BC Hydro and customer / stakeholder groups in their attitudes and actions about using natural gas in applications that it is best suited for.

The fact that the RIB rate structure is not considered in the analysis does not change the impact this study has had on changing the perception towards using natural gas in direct use applications. The results of this study are one of the reasons why BC Hydro is no longer supporting using natural gas in direct use applications, due to the fact that there is no payback to customers who install the natural gas applications.

At the time of the CPR study, TGI expressed concerns with the studies findings due to some of the inputs that were used in the study. Therefore, the RIB implementation would be another variable that would influence the study findings; however since not all residential space and water heating energy demand comes from the RIB Step 2 rate it is not clear how much the incorporating the RIB implementation in the analysis would change the findings.

102.0 Reference: Business Risk – Returns

Exhibit B-3, BCUC IR 50.2

102.1 Please provide the impact of using real, exchange rate adjusted, risk adjusted returns referenced in the response.

Response:

The detailed return data used in the study by Concentric is not provided. Therefore the impact cannot be judged. Concentric provides in Table 10 on page 42 of their report a review of certain macroeconomic factors including Canadian currency movements relative to the U.S. dollar as well as inflation and GDP growth for the period 1981 to 2006.

On a long term basis, inflation in Canada and the U.S. is approximately equivalent, 3.58% for Canada and 3.52% for the U.S. and is highly correlated at 0.87. An inflation adjustment would not have a material impact on the study's conclusions in Mr. Carmichael's judgment.

The value of the Canadian dollar relative to the U.S. dollar has varied in a range of 64 cents to 88 cents during the period. Of the 25 years, in 5 years there was no change in value, 11 years in which the value of the Canadian dollar declined and 9 years in which the value of the Canadian dollar increased, relative to the U.S. dollar. The recent increase in the value of the Canadian dollar (its average value in 2002 was 64 cents) can be linked to increases in commodity prices and the continuing improvement of the Government of Canada's financial position.

As for the impact of foreign exchange movements on investors required rates of return, Concentric, at page 44 of their study, discusses whether there are fundamental differences (such as inflation, political risk and exchange rate risk) which result in required returns in Canada being materially different than those in the U.S. At page 47 of their report, Concentric concludes that there does not appear to be determinative differences to justify a sustained difference in required returns on equity between the Canadian and U.S. equity market. This would suggest that an exchange rate or inflation adjustment is not appropriate.

103.0 Reference: Currency Impacts

Exhibit B-3, BCUC IR 50.3.1

103.1 Please provide some useful indication of the magnitude of the impact of currency exchange rate changes on investments in similar Canadian and US utility stocks during the past decade.

Response:

This is not possible to provide as other than PNG there are no significant pure utilities that are publicly traded in Canada with operations exclusively based in Canada. Over the past decade, the value of utilities in Canada has been impacted by new initiatives undertaken by the utilities, some of which initiatives are regulated, some of which are not regulated, new ownership and/or the restructuring of existing operations. It is not possible to determine the value impact of foreign exchange movements in light of these other developments.

103.2 If TGI argues that market globalization is a significant reason for achieving comparability in ROEs and Capital Structures between Canada and US utilities, shouldn't TGI have taken into account investor expectations for currency valuations?

Response:

TGI has applied to the BCUC for an appropriate return on equity and capital structure which are consistent with levels achieved in other jurisdictions whose economy is highly integrated with Canada. Expected currency valuations are a function of the differences in nominal interest rates. The immaterial difference between the forecast 10-year Government of Canada and U.S. Treasury bond yields over the longer term (see McShane testimony lines 1159-1162) suggests that investors are not expecting a material appreciation or depreciation of the Canadian dollar against the U.S. dollar.

104.0 Reference: Currency Impacts

Exhibit B-3, BCUC IR 51.1

104.1 Given the TGI globalization arguments, please indicate the impact that changing exchange rates would have on the chart on page 148.

Response:

The chart on page 14 adjusts the U.S. allowed returns for the difference in interest rates and the difference in expected long-term inflation rates between the U.S. and Canada. The adjustment of the allowed returns for the difference in interest rates and for differences in the expected inflation rates, as was depicted in the chart on page 14, already incorporates the expected future path of the exchange rates.

Differences between the expected inflation rates between the two countries determine differences in interest rates and, in turn, differences between interest rates between the two countries determine expected exchange rates. Simply stated, differences in the nominal costs of capital determine the expected exchange rates, not vice versa. For example, assume that the nominal yield on a one-year Government of Canada bill was 3%, 0.50% lower than the corresponding one-year U.S. Treasury bill of 3.5% and the spot exchange rate is 1.20. An investor has a choice between investing a Canadian dollar at 3%, so that at the end of the year, he/she has $1.03, or alternatively, the investor could convert the Canadian dollar to U.S. dollars at the spot exchange rate of 1.20, and invest the proceeds at the U.S. rate of 3.5%. At the spot exchange rate, the Canadian investor would receive $U.S. 0.833 (1/1.2), which at the end of the year would be worth $U.S. 0.8625 ($0.833 X 1.035). The forward exchange rate should be equal to that which would permit the investor, at the end of the one year investment period, to convert his/her U.S. dollar investment back to Canadian dollars and earn the same return as he/she would have earned in the Canadian investment. Therefore, in equilibrium the forward exchange rate should equal 1.194, i.e., the return in Canada relative to the return in US or 1.03/.8625. If this were not the case, the forward exchange rate would adjust so that the Canadian and U.S. dollar returns were equivalent. Thus the adjustment of the allowed returns for the difference in interest rates and for differences in the expected inflation rates, as was depicted in the chart on page 14, already incorporates the expected future path of the exchange rates.

105.0 Reference: ROE

Exhibit B-3, BCUC IR 62.1

105.1 Please identify the Approved ROEs for the utilities that had their last ROE setting in 2008.

Response:

The requested information on the allowed ROEs, with the corresponding approved capital structures, is presented below.

Company	Allowed ROE	Allowed Equity Ratio
Consolidated Edison	9.1%	48.0%
Dominion Resources	Settlement; ROE not specified	Settlement; capital structure not specified
Duke Energy	10.5%	55.8%
New Jersey Resources	10.3%	51.2%
Northwest Nat. Gas	10.1%	50.7%
Piedmont Natural Gas	10.6%	51.0%

106.0 Reference: Earnings Test

Exhibit B-3, BCUC IR 66.4

106.1 The IR response concludes with the statement that "The average of annual medians for both the existing sample and the 1999 sample are identical at 12.8%." Please show the annual returns of each of the companies deleted from the sample or added to the sample during the past 10 years along with when the company was deleted or added to the sample.

Response:

The response to BCUC IR 1.66.4 lists each of the companies which were added to or removed from the 1999 sample. The ROEs for the companies which were added to the sample are included in Schedule 20 of Ms. McShane's testimony. The requested annual returns for the 1999 sample are presented in the following table. The ROEs for the companies that are no longer in the sample are included in that file. As stated in response to BCUC IR 1.66.4, "A sample is the outcome or result of the application of a set of screening criteria to a universe of companies; a new sample is selected each time the analysis is done." Ms. McShane does not track the selected samples over time to determine when a particular company is added or subtracted.

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
20 LOW RISK UNREGULATED CANADIAN COMPANIES INCLUDED IN 1999 SAMPLE

Company Name	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average 1991-2007
ANDREW PELLER LTD	10.1	9.3	9.0	10.0	12.3	13.8	13.1	10.3	18.7	6.2	7.9	9.8	12.4	10.1	6.9	10.2	11.5	10.7
CANADA BREAD CO LTD	21.1	13.9	15.6	14.5	12.6	12.8	14.2	1.3	2.7	7.4	8.6	13.9	9.6	14.3	14.5	9.5	13.7	11.8
CANADIAN TIRE CORP -CL A	11.9	6.4	6.9	0.5	10.2	10.4	11.4	13.0	11.2	10.6	11.5	11.9	12.8	13.6	13.9	13.4	14.2	10.8
CARA OPERATIONS LTD -CL A	14.0	12.6	11.7	9.5	12.2	10.9	13.8	7.4	10.5	34.6	10.3	12.8	NA	NA	NA	NA	NA	13.4
CCL INDUSTRIES -CL B	0.1	16.0	2.0	8.6	9.5	10.3	9.6	8.7	9.4	4.7	4.4	4.4	12.4	13.7	32.3	12.7	21.6	10.6
CORBY (H.) DISTILLERY -CL A	10.9	21.6	23.6	30.8	28.0	22.3	20.9	29.3	46.5	37.0	43.8	31.5	30.5	29.6	30.4	18.6	55.5	30.1
DOVER INDUSTRIES LTD	13.3	11.2	12.0	12.1	10.5	7.0	3.8	8.0	5.5	3.0	9.8	2.6	5.2	5.7	15.6	10.1	13.7	8.8
DUPONT CANADA -CL A	9.2	12.6	9.4	19.9	20.4	19.7	20.6	27.3	19.5	18.2	13.6	14.1	NA	NA	NA	NA	NA	17.0
EMPIRE CO LTD -CL A	3.7	6.8	12.3	9.4	3.9	11.9	17.9	21.7	13.3	69.1	16.4	11.4	11.6	11.4	16.2	10.3	14.0	15.4
IMPERIAL OIL LTD	2.3	2.9	4.2	5.7	8.6	15.0	18.9	12.9	13.5	32.4	28.4	25.1	30.6	33.9	40.1	43.4	41.6	21.2
LEON'S FURNITURE LTD	14.6	11.4	16.4	15.3	14.0	13.4	15.1	16.7	21.1	19.3	17.3	17.1	16.5	18.9	19.2	19.6	19.2	16.8
LOBLAW COMPANIES LTD	13.2	8.7	9.6	12.4	13.3	14.2	15.3	12.8	13.7	15.7	16.8	18.9	19.1	19.1	13.2	-3.9	6.0	12.8
OSHAWA GROUP LTD -CL A	5.7	6.4	7.3	7.3	8.4	6.8	4.8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6.7
QUEBECOR INC -CL B	4.9	16.5	10.8	11.3	20.6	14.2	12.4	13.0	30.5	48.0	-9.0	4.5	4.6	7.9	4.8	-6.8	-111.0	4.5
REITMANS (CANADA) -CL A	9.4	15.4	11.1	9.0	6.2	0.8	8.9	9.4	30.1	10.2	12.6	10.5	15.4	22.0	23.5	20.0	24.7	14.1
SHELL CANADA LTD -CL A	0.4	2.7	0.6	10.7	16.0	8.9	14.8	13.1	17.7	22.1	23.3	11.4	15.2	21.2	27.3	19.5	NA	14.1
THOMSON-REUTERS CORP (CDN)	9.9	6.0	10.0	14.6	22.4	14.2	12.9	34.7	8.0	17.9	10.2	7.3	8.8	10.3	9.3	11.0	31.1	14.0
U A P INC -CL A	6.8	6.9	8.9	11.6	10.0	10.2	8.1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.9
WESTON (GEORGE) LTD	7.0	3.2	4.5	8.7	12.9	15.1	14.5	37.3	14.0	17.4	18.5	18.3	19.4	10.2	16.2	1.6	12.7	13.6
WINPAK LTD	10.7	12.4	13.7	13.0	11.4	12.7	10.9	13.0	15.1	15.2	14.0	20.7	14.7	12.4	9.6	12.5	7.4	12.9
Mean	**8.9**	**10.1**	**10.0**	**11.7**	**13.2**	**12.2**	**13.1**	**16.1**	**16.7**	**21.6**	**14.4**	**13.7**	**14.9**	**15.9**	**18.3**	**12.6**	**11.7**	**13.4**
Median	**9.7**	**10.2**	**9.8**	**11.0**	**12.3**	**12.7**	**13.5**	**13.0**	**13.8**	**17.6**	**13.1**	**12.3**	**13.8**	**13.6**	**15.9**	**11.8**	**14.0**	**13.1**
Average of Annual Medians																		**12.8**

Source: Standard and Poor's Research Insight.

107.0 Reference: DCF Analysis – Update

Exhibit B-3, BCUC IR 79.3

107.1 Since "Dr. Vander Weide uses the most recent prices available at the time of his analysis", please update that analysis to the end of July and indicate the adjustments he would make to each variable in his DCF analysis.

Response:

In responding to this request, Dr. Vander Weide notes that he does not "adjust" the variables in his DCF analysis. Rather, to update his DCF studies, Dr. Vander Weide employs the same methodology described in his written evidence at pages 33 – 34. Thus, when Dr. Vander Weide performs his DCF analyses, he identifies a set of comparable companies, as described in his written evidence, and obtains each company's stock price, dividend, and growth data necessary to perform the DCF analysis. The stock price, dividend, and growth data for each company are the marketplace data, and no "adjustments" are made to these data inputs.

At the time of the filing of his written evidence, Dr. Vander Weide's DCF analyses uses market data available through the end of February 2009. Exhibit 8 summarizes Dr. Vander Weide's discounted cash flow analysis for a large group of Value Line electric companies that met his selection criteria at the time of his studies. The average DCF result for this group of electric companies using data through February 2009 is 12.4 percent. Updating his DCF analysis of Value Line electric utilities using data through July 2009, Dr. Vander Weide obtains an average DCF result of 11.5 percent.

Exhibit 9 summarizes Dr. Vander Weide's discounted cash flow analysis for a large group of Value Line natural gas utilities that met his selection criteria at the time of his studies. The average DCF result for this group of natural gas utilities using data through February 2009 is 11.5 percent. Updating his DCF analysis of Value Line gas utilities using data through July 2009, Dr. Vander Weide obtains an average DCF result of 11.9 percent.

UPDATED EXHIBIT 8 STUDIES IN RESPONSE TO BCUC IR 2, 107.1

SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS FOR
VALUE LINE ELECTRIC COMPANIES USING DATA THROUGH JULY 2009

Line No.	Company	d_0	P_0	Growth	Cost of Equity
1	ALLETE	0.440	28.253	6.00%	13.2%
2	Alliant Energy	0.375	24.868	4.60%	11.4%
3	Amer. Elec. Power	0.410	27.922	3.03%	9.6%
4	CMS Energy Corp.	0.125	11.923	6.75%	11.3%
5	Consol. Edison	0.590	36.937	2.44%	9.5%
6	Dominion Resources	0.438	32.500	6.36%	12.3%
7	DPL Inc.	0.285	22.743	9.32%	15.3%
8	Duke Energy	0.230	14.380	3.50%	10.7%
9	Edison Int'l	0.310	30.488	1.32%	5.7%
10	Entergy Corp.	0.750	74.348	9.02%	13.9%
11	Exelon Corp.	0.525	49.363	2.66%	7.3%
12	FirstEnergy Corp.	0.550	39.490	6.67%	13.2%
13	FPL Group	0.473	56.427	9.59%	13.5%
14	Hawaiian Elec.	0.310	17.525	4.87%	13.1%
15	Northeast Utilities	0.238	21.588	8.33%	13.3%
16	NSTAR	0.375	31.307	6.25%	11.7%
17	Pepco Holdings	0.270	13.098	3.67%	13.1%
18	PG&E Corp.	0.420	37.525	7.07%	12.1%
19	Pinnacle West Capital	0.525	28.895	5.67%	14.2%
20	Portland General	0.245	18.690	6.99%	13.2%
21	PPL Corp.	0.345	32.351	12.67%	18.0%
22	Progress Energy	0.620	36.575	5.36%	13.2%
23	Public Serv. Enterprise	0.333	32.113	5.67%	10.4%
24	SCANA Corp.	0.470	31.740	5.34%	12.1%
25	Sempra Energy	0.390	48.353	6.61%	10.2%
26	Southern Co.	0.438	30.066	4.97%	11.5%

Line No.	Company	d_0	P_0	Growth	Cost of Equity
27	TECO Energy	0.200	11.895	9.04%	17.2%
28	UIL Holdings	0.432	22.626	4.47%	13.3%
29	Vectren Corp.	0.335	23.225	6.42%	13.1%
30	Westar Energy	0.300	18.305	3.32%	10.6%
31	Wisconsin Energy	0.338	40.333	9.03%	12.6%
32	Xcel Energy Inc.	0.238	18.187	6.58%	12.7%
33	Market-weighted Average				11.5%

Notes:

d_0 = Most recent quarterly dividend.

d_1,d_2,d_3,d_4 = Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g).

P_0 = Average of the monthly high and low stock prices during the three months ending July 2009 per Thomson Reuters.

FC = Flotation costs expressed as a percent of gross proceeds.

g = I/B/E/S forecast of future earnings growth July 2009.

k = Cost of equity using the quarterly version of the DCF model.

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

UPDATED EXHIBIT 9 STUDIES IN RESPONSE TO BCUC IR 2, 107.1

SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS FOR
VALUE LINE NATURAL GAS COMPANIES USING DATA THROUGH JULY 2009

Line No.	Company	d_0	P_0	Growth	Cost of Equity
1	AGL Resources	0.430	31.017	4.25%	10.5%
2	Atmos Energy	0.330	25.230	5.00%	11.0%
3	EQT Corp.	0.220	35.962	9.00%	11.9%
4	National Fuel Gas	0.325	35.078	8.50%	12.9%
5	Nicor Inc.	0.465	33.610	4.33%	10.6%
6	NiSource Inc.	0.230	11.570	3.00%	12.0%
7	Northwest Nat. Gas	0.395	43.398	4.75%	8.9%
8	ONEOK Inc.	0.400	29.035	7.25%	13.8%
9	Piedmont Natural Gas	0.270	23.733	6.93%	12.2%
10	South Jersey Inds.	0.298	34.848	9.67%	13.7%
11	Southwest Gas	0.238	21.663	6.00%	10.9%
12	Market-Weighted Average				11.9%

Notes:

d_0 = Most recent quarterly dividend.

d_1,d_2,d_3,d_4 = Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g).

P_0 = Average of the monthly high and low stock prices during the three months ending July 2009 per Thomson Reuters.

FC = Flotation costs expressed as a percent of gross proceeds.

g = I/B/E/S forecast of future earnings growth July 2009.[**2**]

k = Cost of equity using the quarterly version of the DCF model.

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

[2] Although I normally specify that the I/B/E/S long-term earnings growth forecast must include the forecasts of at least three analysts, in July 2009 there are only five companies with growth forecasts from at least three analysts. In this study, therefore, I also include results for companies that had growth forecasts based on two analysts' growth forecasts.

108.0 Reference: Exchange Rate Adjustments

Exhibit B-3, BCUC IR 50.3.2, Page 145

108.1 Please report Canadian and US returns, all converted into Canadian Dollars (i.e., use Canadian Dollars as the common currency). Please also report Canadian and US returns, all converted into US Dollars (i.e., use US Dollars as the common currency).

Response:

See response to BCUC IR 2.102.1.

109.0 Reference: Econometrics

Exhibit B-3, BCUC IR 78, Page 205

109.1 Since it is econometrically problematic to estimate variances and covariances on variables that are not covariance stationary, the method of variable transformation employed in the regressions involving DCFcomp and Ib may be problematic. As was originally requested in BCUC IR#1, please therefore calculate and report the results of a unit root test (Dickey-Fuller Test) on the raw variables DCFcomp and Ib (as explained in standard econometrics textbooks). If these raw variables are non-stationary (i.e., a unit root cannot be rejected with 95% confidence), then please perform the regressions on the first differences of the raw variables (as explained in standard econometrics textbooks) and report the results.

Response:

Dr. Vander Weide does not believe that his regression analysis is econometrically “problematic.” However, the results of the unit root tests and the requested regressions are shown below.

Dickey-Fuller Test and Regression Results for Natural Gas Companies

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: DeltaRP

Independent variable: LagRP

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.00591639	0.00248321	2.38256	0.0187
Slope	-0.0930997	0.0397965	-2.33939	0.0209

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.0000841762	1	0.0000841762	5.47	0.0209
Residual	0.001938	126	0.0000153809		
Total (Corr.)	0.00202217	127			

Correlation Coefficient = -0.204026

R-squared = 4.16266 percent

R-squared (adjusted for d.f.) = 3.40204 percent

Standard Error of Est. = 0.00392185

Mean absolute error = 0.00288513

Durbin-Watson statistic = 1.92908 (P=0.3450)

Lag 1 residual autocorrelation = 0.033249

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: DeltaDCF

Independent variable: LagDCF

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.00445954	0.00282213	1.58021	0.1166
Slope	-0.0389331	0.0245775	-1.5841	0.1157

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.0000241318	1	0.0000241318	2.51	0.1157
Residual	0.0012117	1260	.00000961671		

Total (Corr.)	0.00123584	127

Correlation Coefficient = -0.139738

R-squared = 1.95267 percent

R-squared (adjusted for d.f.) = 1.17452 percent

Standard Error of Est. = 0.00310108

Mean absolute error = 0.00219344

Durbin-Watson statistic = 1.8911 (P=0.2700)

Lag 1 residual autocorrelation = 0.0475995

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: Gas Delta Yield

Independent variable: Lag Yield

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.00237162	0.00166392	1.42532	0.1565
Slope	-0.0481088	0.0314532	-1.52954	0.1286

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.0000126606	1	0.0000126606	2.34	0.1286
Residual	0.000681877	126	0.00000541173		
Total (Corr.)	0.000694538	127			

Correlation Coefficient = -0.135014

R-squared = 1.82289 percent

R-squared (adjusted for d.f.) = 1.0437 percent

Standard Error of Est. = 0.00232631

Mean absolute error = 0.00161181

Durbin-Watson statistic = 1.98113 (P=0.4577)

Lag 1 residual autocorrelation = 0.00283098

Regression Analysis - Linear model: Y = a + b*X				
Dependent variable: DeltaRP_1				
Independent variable: DeltaYield_1				
Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	-1.49492E-8	0.000277078	-0.0000539531	1.0000
Slope	-1.06609	0.11869	-8.98212	0.0000

Analysis of Variance					
Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.000789371	1	0.000789371	80.68	0.0000
Residual	0.0012328	126	0.00000978415		
Total (Corr.)	0.00202217	127			

Correlation Coefficient = -0.624786
R-squared = 39.0358 percent
R-squared (adjusted for d.f.) = 38.5519 percent
Standard Error of Est. = 0.00312796
Mean absolute error = 0.00217718
Durbin-Watson statistic = 1.92099 (P=0.3283)
Lag 1 residual autocorrelation = 0.0322875

Regression Analysis - Linear model: Y = a + b*X				
Dependent variable: DeltaDCF_1				
Independent variable: DeltaYield_2				
		Standard	T	
Parameter	Estimate	Error	Statistic	P-Value
Intercept	-1.49492E-8	0.000277078	-0.0000539531	1.0000
Slope	-0.066087	0.11869	-0.556804	0.5786

Analysis of Variance				
Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.00000303339	1	0.00000303339	0.31	0.5786
Residual	0.0012328	126	0.00000978415		
Total (Corr.)	0.00123584	127			

Correlation Coefficient = -0.0495431
R-squared = 0.245452 percent
R-squared (adjusted for d.f.) = -0.546251 percent
Standard Error of Est. = 0.00312796
Mean absolute error = 0.00217718
Durbin-Watson statistic = 1.92099 (P=0.3283)
Lag 1 residual autocorrelation = 0.0322875

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: Gas Risk Premium
Independent variable: Gas Delta Yield

Standard T
Parameter Estimate Error Statistic P-Value

Intercept 0.0618008 0.000762952 81.0022 0.0000
Slope -0.913577 0.32682 -2.79536 0.0060

Analysis of Variance

Source Sum of Squares Df Mean Square F-Ratio P-Value

Model 0.000579678 1 0.000579678 7.81 0.0060
Residual 0.00934723 126 0.0000741844

Total (Corr.) 0.00992691 127
Correlation Coefficient = -0.24165
R-squared = 5.83946 percent
R-squared (adjusted for d.f.) = 5.09215 percent
Standard Error of Est. = 0.00861304
Mean absolute error = 0.0074486
Durbin-Watson statistic = 0.167854 (P=0.0000)
Lag 1 residual autocorrelation = 0.897133

Dickey-Fuller Test and Regression Results for Electric Companies

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: Delta RP

Independent variable: Lag Risk Premium

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.00341054	0.00216746	1.57352	0.1184
Slope	-0.0500888	0.0344236	-1.45507	0.1485

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.0000387002	1	0.0000387002	2.12	0.1485
Residual	0.00202893	111	0.0000182787		
Total (Corr.)	0.00206764	112			

Correlation Coefficient = -0.136811

R-squared = 1.87172 percent

R-squared (adjusted for d.f.) = 0.987677 percent

Standard Error of Est. = 0.00427536

Mean absolute error = 0.00307278

Durbin-Watson statistic = 2.23342 (P=0.1081)

Lag 1 residual autocorrelation = -0.11736

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: DeltaDCF

Independent variable: LagDCF

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.00343978	0.00277214	1.24084	0.2173
Slope	-0.0296015	0.0242315	-1.22161	0.2244

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.0000167197	1	0.0000167197	1.49	0.2244
Residual	0.00124361	111	0.0000112037		
Total (Corr.)	0.00126033	112			

Correlation Coefficient = -0.115179

R-squared = 1.32661 percent

R-squared (adjusted for d.f.) = 0.437663 percent

Standard Error of Est. = 0.00334719

Mean absolute error = 0.00248186

Durbin-Watson statistic = 2.10495 (P=0.2896)

Lag 1 residual autocorrelation = -0.0565737

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: DeltaYield

Independent variable: LagYield

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.00325658	0.00179045	1.81886	0.0716
Slope	-0.0674413	0.0343	-1.96622	0.0518

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.0000218352	1	0.0000218352	3.87	0.0518
Residual	0.000626926	111	0.00000564798		
Total (Corr.)	0.000648761	112			

Correlation Coefficient = -0.183458

R-squared = 3.36568 percent

R-squared (adjusted for d.f.) = 2.4951 percent

Standard Error of Est. = 0.00237655

Mean absolute error = 0.00158858

Durbin-Watson statistic = 2.01626 (P=0.4658)

Lag 1 residual autocorrelation = -0.0202138

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: DeltaRP_1

Independent variable: DeltaYield_1

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.00004635	0.000317298	0.146077	0.8841
Slope	-1.12219	0.131784	-8.51536	0.0000

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.000816991	1	0.000816991	72.51	0.0000
Residual	0.00125064	111	0.0000112671		

Total (Corr.)	0.00206764	112

Correlation Coefficient = -0.628596

R-squared = 39.5133 percent

R-squared (adjusted for d.f.) = 38.9684 percent

Standard Error of Est. = 0.00335665

Mean absolute error = 0.00245894

Durbin-Watson statistic = 2.10184 (P=0.2953)

Lag 1 residual autocorrelation = -0.0556481

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: DeltaDCF

Independent variable: DeltaYield

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.00004635	0.000317298	0.146077	0.8841
Slope	-0.122189	0.131784	-0.927192	0.3558

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.00000968613	1	0.00000968613	0.86	0.3558
Residual	0.00125064	111	0.0000112671		
Total (Corr.)	0.00126033	112			

Correlation Coefficient = -0.0876663

R-squared = 0.768539 percent

R-squared (adjusted for d.f.) = -0.125438 percent

Standard Error of Est. = 0.00335665

Mean absolute error = 0.00245894

Durbin-Watson statistic = 2.10184 (P=0.2953)

Lag 1 residual autocorrelation = -0.0556481

Regression Analysis - Linear model: Y = a + b*X

Dependent variable: RiskPremium

Independent variable: DeltaYield_2

Parameter	Estimate	Standard Error	T Statistic	P-Value
Intercept	0.0619394	0.00110856	55.8736	0.0000
Slope	-1.02796	0.460422	-2.23265	0.0276

Analysis of Variance

Source	Sum of Squares	Df	Mean Square	F-Ratio	P-Value
Model	0.000685551	1	0.000685551	4.98	0.0276
Residual	0.0152658	111	0.00013753		
Total (Corr.)	0.0159514	112			

Correlation Coefficient = -0.20731

R-squared = 4.29776 percent

R-squared (adjusted for d.f.) = 3.43558 percent

Standard Error of Est. = 0.0117273

Mean absolute error = 0.00938406

Durbin-Watson statistic = 0.107041 (P=0.0000)

Lag 1 residual autocorrelation = 0.916234

110.0 Reference: DCF Robustness

Exhibit B-3, BCUC IR 79.3.1, Page 209

110.1 Please perform, and report the results of, the robustness exercise that was originally requested in question 79.3.1 of BCUC IR#1. If using "P" calculated in the different ways indicated in question 79.3.1 requires using different values for "g" and "D" then please feel free to use such different values of "g" and "D" and explain why you are doing so and report what values are being used.

Response:

Question 79.3 of BCUC IR#1 suggests that recent DCF results may be distorted by the fact that the stock price in the DCF model is "significantly below its trend." The best way to determine the effect of the relative movement in stock prices over the last year on the DCF result is to examine the monthly DCF results over the last year shown in Exhibit 5 and Exhibit 6 of Dr. Vander Weide's written testimony. It would not be meaningful to adjust the growth rates and dividends so that they can be applied to average prices over the last year. Please also see response to BCUC IR 2.107.1.

111.0 Reference: Credit Rating Agency Reports

Exhibit B-3-3, Attachment 86.2, Moody’s Credit Rating dated May 27, 2008, p. 2

The Moody’s credit rating report for TGI dated May 27, 2008 on page 2 cites Moody’s rating methodology for North American Regulated Gas Distribution Industry (Local Distribution Companies).

111.1 Please file the Moody’s rating methodology for North American Regulated Gas Distribution Industry (Local Distribution Companies).

Response:

Attachment 111.1 contains Moodys NA Reg Gas LDC Methodology.

Attachment 92.1

SQUAMISH GAS ARRANGEMENTS TERMINATION AGREEMENT

THIS AGREEMENT is made the 5th day of October, 2006,

AMONG

HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF BRITISH COLUMBIA, represented by the Minister of Energy, Mines and Petroleum Resources

("**British Columbia**");

AND:

TERASEN GAS (VANCOUVER ISLAND) INC., a company duly incorporated under the laws of the Province of British Columbia with an office at 16705 Fraser Highway, Surrey, British Columbia (formerly Pacific Coast Energy Corporation)

("**TGVI**");

AND:

TERASEN GAS (SQUAMISH) INC., a company duly incorporated under the laws of the Province of British Columbia with an office at 16705 Fraser Highway, Surrey, British Columbia

("**TGS**");

AND:

TERASEN GAS INC., a company duly incorporated under the laws of the Province of British Columbia with an office at 16705 Fraser Highway, Surrey, British Columbia

("**TGI**");

WHEREAS:

A. TGS (formerly Squamish Gas Company Limited) is the holder of a disposition order pursuant to the *Utilities Commission Act* dated August 6, 1991, authorizing the construction and operation of a gate station and related natural gas distribution facilities for the distribution of natural gas in the District of Squamish;

B. British Columbia and TGS entered into an agreement entitled "Squamish Rate Stabilization Agreement" as of the 9th day of July, 1992, as amended by agreement made effective as of June 19, 2000 (collectively, the "RSA"), which provides for the stabilization of

the retail prices at which gas is sold to consumers in the area served by the gas distribution system operated by TGS;

C. British Columbia and TGS wish to terminate the RSA on the terms and conditions contained herein;

D. Her Majesty the Queen in Right of Canada represented by the Minister of Natural Resources (formerly the Minister of Energy, Mines and Resources), British Columbia and TGVI (formerly Pacific Coast Energy Corporation) entered into an agreement made as of the 3rd day of November, 1989, and amendments thereto dated as of the 9th day of October, 1990 and as of the 4th day of March 1992 (collectively, the "Binding Agreement"), under which Her Majesty the Queen in Right of Canada represented by the Minister of Natural Resources (formerly the Minister of Energy, Mines and Resources) and British Columbia agreed to provide certain financial assistance for the construction and operation by TGVI of a natural gas transmission pipeline system extending from Coquitlam, British Columbia to various points on Vancouver Island, including a rate stabilization facility for the stabilization of the retail prices at which gas delivered to TGS by TGVI through such pipeline is sold to consumers in the area served by the gas distribution system operated by TGS (the "RSF");

E. The Binding Agreement was terminated effective December 31, 1994, but British Columbia and TGVI agreed as between themselves to continue the RSF thereafter, and entered into an agreement entitled "Rate Stabilization Facility Continuation Agreement" dated as of the 14th day of December, 1995 (the "RSFCA") in that regard;

F. British Columbia and TGVI wish to terminate the RSFCA on the terms and conditions contained herein;

G. TGS committed to pay to British Columbia certain amounts in respect of any increased funding required under the RSF resulting from TGS's main extensions to Brackendale and the Garibaldi Highlands (the "Main Extension Obligations") pursuant to certain communications among TGS, British Columbia and the British Columbia Utilities Commission (the "Commission") in 1997 and 1998, including a letter dated November 17, 1997 pursuant to which TGS applied to the Commission for approval to extend natural gas service to Brackendale and Garibaldi Highlands, a letter dated July 15, 1998 from the Assistant Deputy Minister of the Ministry of Energy and Mines to the Commission, and a letter dated July 16, 1998 from the Commission to TGS (collectively, the "1997 and 1998 Communications");

H. TGS and British Columbia wish to terminate the Main Extension Obligations on the terms and conditions contained herein;

I. TGS and TGI intend to amalgamate and to continue under the name Terasen Gas Inc. ("Amalgamated TGI");

J. TGS and TGVI entered into a Transportation Service Agreement dated April 1, 1990, under which TGVI agreed to transport and deliver gas to TGS (the "TSA"); and

K. TGS and TGVI wish to amend the TSA to provide for transportation of gas by TGVI to Squamish for Amalgamated TGI.

IN CONSIDERATION of the mutual promises contained in this Agreement, the parties agree as follows:

SECTION 1
INTERPRETATION

1.1 **Governing Law**. This Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties to this Agreement submit and attorn to the exclusive jurisdiction of the Courts of the Province of British Columbia.

1.2 **Headings**. The headings in this Agreement are inserted for convenience of reference only and shall not affect the interpretation of this Agreement.

1.3 **Entire Agreement**. This Agreement constitutes the entire agreement among the parties and supersedes all prior agreements and understandings, oral or written, by and among the parties with respect to the subject matter of this Agreement.

1.4 **Severability**. Should any provision of this Agreement be void or unenforceable it shall be severed from this Agreement and the remainder of this Agreement shall remain in full force and effect and shall be interpreted and construed as if the stricken provision had never formed part of this Agreement.

1.5 **Schedules**. The following are the Schedules attached to and forming a part of this Agreement:

Schedule "A"	Special Direction No. 3
Schedule "B"	Amendment to Special Direction 1510
Schedule "C"	Regulation stating that section 53 of the *Utilities Commission Act* does not apply in respect of TGS or TGI in relation to an amalgamation of those two corporations

SECTION 2
TERMINATION AND AMENDMENT OF SQUAMISH GAS ARRANGEMENTS

2.1 **Termination of RSA**. British Columbia and TGS hereby agree to terminate the RSA effective as of January 1, 2007 (the "Effective Date").

2.2 **Termination of the RSFCA**. Except as provided herein, British Columbia and TGVI hereby agree to terminate the RSFCA effective as of the Effective Date. The obligations of British Columbia and TGVI pursuant to sections 3.03, 3.04, 3.05 and 3.06 of the RSFCA, to the extent those obligations relate to or arise from Unit Toll Payments paid by, or Unit Toll Receipts received by, TGVI for gas transported to TGS on or before December 31, 2006 will continue and are not released by termination of the RSFCA.

2.3 **Termination of the Main Extension Obligations**. British Columbia and TGS hereby agree to terminate the Main Extension Obligations effective as of the Effective Date.

2.4 **Amendment of TSA**. TGVI and TGS agree to amend the TSA, effective as of the Effective Date, as follows:

(a) The definition of "Unit Toll" in Section 1.01 is deleted and replaced with the following: "'Unit Toll" means $1.05 per gigajoule';

(b) Section 5 is deleted in its entirety;

(c) Sections 6.01 is deleted and replaced with the following: "The term of this Agreement shall commence on the date that Gas is taken by Shipper at any one or more of the Delivery Points and shall continue until the later of (i) the date upon which the balance of the Revenue Deficiency Deferral Account of TGVI has been reduced to zero, and (ii) the date upon which the Commission establishes a new rate for the transportation of Gas to Shipper.";

(d) Section 10.01 is deleted and replaced with the following: "Statements and payments shall be in accordance with Section 8 of the TGVI Transmission Transportation Service tariff.";

(e) Section 16.03 is deleted and replaced with the following:

"The address for both parties hereto for the purpose of giving notice is: 16705 Fraser Highway, Surrey, B.C., V4N 0E8"; and

(f) Sections 10.02, 10.03, 10.04 and 10.05 are deleted.

SECTION 3
TERMINATION PAYMENTS

3.1 **Main Extension Obligations**. TGS hereby agrees to pay to British Columbia the amount of $1.75 million by December 31, 2006. TGS and British Columbia acknowledge that this amount represents the difference between the Main Extension Obligations and the post December 31, 2006 obligations of British Columbia related to the supply and transportation of natural gas to TGS under the operation of the RSA and the RSFCA.

SECTION 4
RELEASES

4.1 **Release of Main Extension Obligations**. British Columbia hereby releases TGS of and from any and all actions, causes of action, claims, demands and damages howsoever arising which the releasor now has or may hereafter have against the releasee by reason of any cause, act, deed, matter, thing or omission in connection with the Main Extension Obligations.

SECTION 5
ORDERS IN COUNCIL

5.1 **Orders in Council**. Subject to Section 5.1, British Columbia hereby agrees to issue, on or before November 30, 2006 and effective as of the Effective Date, Special Direction No. 3, the amendment to Special Direction 1510, and a Regulation, as set out in Schedules "A", "B" and "C" respectively (collectively the "Orders in Council").

5.2 **Indemnity**. Nothing in this Agreement shall obligate British Columbia to issue the Orders In Council or preclude British Columbia from making further or other amendments to Special Direction 1510. In the event:

(a) British Columbia does not issue the Orders in Council on or before the date set out in Section 5.1;

(b) Special Direction 1510 is amended, cancelled, superseded or in any other way altered, including without limitation, an alteration that results from the Province giving any other direction to the Commission; or

(c) Special Direction No. 3 or the amendment to Special Direction 1510 is determined by a court of competent jurisdiction, as a result of proceedings brought by some person not a party to this Agreement, to contain directions that the Commission is not legally obligated to comply with ,

such that in any case, any or all of TGS, TGVI and TGI are adversely affected, British Columbia shall indemnify any or all of TGS, TGVI and TGI, as the case may be, from and against all costs, expenses and losses suffered or incurred by any or all of TGS, TGVI and TGI, as the case may be, and arising or resulting from the failure to issue the Orders in Council as described in (a), alteration as described in (b) or determination as described in (c) to the same extent as if such failure, alteration or determination were a breach of contract by British Columbia giving rise to a claim for damages by any or all of TGS, TGVI and TGI, as the case may be. British Columbia represents that it has received all necessary approvals under the *Guarantees and Indemnities Regulation* to the indemnities contained in this Section.

5.3 **Lower Mainland Service Area**. As soon as reasonably practicable after Special Direction No. 3 comes into effect, amalgamated TGI will request that the Commission amend the definition of "Lower Mainland Service Area" contained in the General Terms and Conditions of the Terasen Gas Inc. Tariff to include "Squamish".

SECTION 6
GENERAL

6.1 **Enurement**. This Agreement shall enure to the benefit of and be binding upon the parties and their respective successors.

6.2 **Time of the Essence**. Time is expressly declared to be of the essence of this Agreement.

6.3 **Waiver**. Any waiver by a party or any failure on a party's part to exercise any of its rights in respect of this Agreement shall be limited to the particular instance and shall not extend to any other instance or matter in this Agreement or in any way otherwise affect the rights or remedies of such party.

6.4 **Further Assurances**. The parties agree to execute and deliver all such other and additional instruments or documents and to do all such other acts and things as may be necessary to give full effect to this Agreement.

6.5 **Counterparts**. This Agreement may be executed in one or more counterparts or by facsimile transmission and if so executed such counterparts or facsimile transmissions shall be read and construed together as if they formed one document.

IN WITNESS WHEREOF the parties have executed this Agreement on the date first above written.

Signed on behalf of **HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF BRITISH COLUMBIA** by the Minister of Energy, Mines and Petroleum Resources

Minister of Energy, Mines and Petroleum Resources

TERASEN GAS (VANCOUVER ISLAND) INC.

Authorized Signatory

Authorized Signatory

TERASEN GAS (SQUAMISH) INC.

Per: Authorized Signatory

Per: Authorized Signatory

TERASEN GAS INC

Per: Authorized Signatory

Authorized Signatory

SCHEDULE "A"
SPECIAL DIRECTION NO. 3

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 768 *, Approved and Ordered* NOV - 2 2006

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that, effective January 1, 2007, the attached Special Direction is made.

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Vancouver Island Natural Gas Pipeline Act*, R.S.B.C. 1996, c. 474, s. 7 (3) and (4)

Other (specify):-

September 29, 2006

935 /2006/7

VANCOUVER ISLAND NATURAL GAS PIPELINE SPECIAL DIRECTION NO. 3 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Definitions

1 In this Special Direction:

"Act" means the *Vancouver Island Natural Gas Pipeline Act*;

"amalgamated TGI" means the amalgamated entity resulting from the amalgamation of TGI and TGS;

"amended TSA" means the SGTSA as amended by the Termination Agreement;

"commission" means the British Columbia Utilities Commission;

"PBR" means the settlement agreement approved by the commission under order G-51-03;

"SGTSA" means the Squamish Gas Transportation Service Agreement dated April 1, 1990 and made between Pacific Coast Energy Corporation and Squamish Gas Co. Ltd.;

"Special Direction 1510" means the Vancouver Island Natural Gas Pipeline Special Direction issued to the British Columbia Utilities Commission by Order in Council 1510/95;

"Termination Agreement" means the Squamish Gas Arrangements Termination Agreement dated October 4, 2006 and made between Her Majesty the Queen in right of the Province of British Columbia, TGVI, TGS and TGI;

"TGI" means Terasen Gas Inc.;

"TGS" means Terasen Gas (Squamish) Inc.;

"TGVI" means Terasen Gas (Vancouver Island) Inc.;

"Unit Toll" has the same meaning as in the amended TSA.

Application

2 This Special Direction is issued to the commission under section 7 (3) and (4) of the Act.

TGVI tolls for service

3 The commission must, for so long as the amended TSA remains in effect, fix the rate that may be charged by TGVI to amalgamated TGI for services provided under the amended TSA at the Unit Toll.

Amended TSA

4 For the purposes of section 3, the commission must consent to the amendment of the SGTSA as provided for in the Termination Agreement.

Revenue derived from TGVI tolls for service

5 For so long as the amended TSA remains in effect, the commission must treat the rate paid by amalgamated TGI under section 3 of this special direction as the only revenues

received by TGVI in recovery of its cost of service with respect to the transportation and delivery of gas under that agreement.

Treatment of toll payments

6 In regulating and fixing rates for amalgamated TGI, the commission must treat, as a cost appropriately recorded in the Midstream Cost Reconciliation Account of amalgamated TGI, all rates paid by amalgamated TGI to TGVI under the amended TSA and recorded by amalgamated TGI in that account.

Rates to be regulated in accordance with PBR

7 Subject to this special direction, the commission must, for so long as the PBR remains in effect, regulate and fix rates for amalgamated TGI in accordance with the PBR.

Application of tariffs

8 In regulating and fixing rates for amalgamated TGI, the commission must apply the Terasen Gas Inc. Tariff and must not apply the Terasen Gas (Squamish) Inc. Gas Tariff.

Amendment of General Terms and Conditions

9 In regulating and fixing rates for amalgamated TGI, the commission must treat the area served by TGS as at December 31, 2006 as being within the "Lower Mainland Service Area" as defined in the General Terms & Conditions of the Terasen Gas Inc. Tariff.

Characterization of assets

10 Assets of TGS that on the amalgamation of TGS and TGI become assets of amalgamated TGI are to be treated by the commission as being, at the effective date of the amalgamation, used and useful assets of amalgamated TGI.

Rate base

11 The commission must, for so long as the PBR remains in force, treat the rate base of amalgamated TGI as being,

(a) on January 1, 2007, an amount equal to

(i) TGS's rate base as at December 31, 2006, plus

(ii) TGI's rate base, as determined under the PBR, as at December 31, 2006, and

(b) after that, the amount referred to in paragraph (a) as adjusted under the PBR.

Customers

12 The commission must treat the number of customers of amalgamated TGI as being, on January 1, 2007, the number equal to

(a) the number of TGS's customers as at December 31, 2006, plus

(b) the number of TGI's customers as at December 31, 2006.

Operating and maintenance expenses

13 For so long as the PBR remains in effect, the commission must determine the operating and maintenance expense of amalgamated TGI in accordance with the PBR, and, for that purpose, the number of customers of amalgamated TGI that must be taken into account for any calendar year is the number of customers, including customers in the area served by TGS as at December 31, 2006, that has been forecast for amalgamated TGI, and accepted by the commission, for that calendar year.

Rate base deferral account

14 (1) For the purposes of subsection (2), the commission must approve the establishment by amalgamated TGI of a rate base deferral account to record

(a) the expenses that the commission accepts were incurred by TGI, TGS and amalgamated TGI to effect the amalgamation of TGI and TGS and to address issues relating to that amalgamation, and

(b) for each year the PBR remains in effect, the difference between

(i) the operating and maintenance expenses that TGS would have been allowed in 2007 in its cost of service, had it not amalgamated with TGI, based on the number of customers of TGS as at December 31, 2006, and

(ii) the operating and maintenance expenses that, under the PBR, are allowed to amalgamated TGI in 2007 for that same number of customers.

(2) If amalgamated TGI establishes a rate base deferral account in accordance with subsection (1), the commission must, after the expiry of the PBR, fix the rates for amalgamated TGI in such a way as to allow amalgamated TGI to recover from its customers, in the manner and over the period considered appropriate by the commission, the amounts recorded in that account.

Treatment of capital structure

15 (1) In this section, **"differential"** means the positive difference between

(a) the weighted average, based on the relative rate bases of TGI and TGS, of

(i) the appropriate common equity component allowed in the capital structure of TGI by order G-14-06, and

(ii) the appropriate common equity component allowed in the capital structure of TGS for 2006, and

(b) the appropriate common equity component allowed in the capital structure of TGI by order G-14-06.

(2) For the purpose of regulating and fixing rates for amalgamated TGI, the commission must, unless and until it determines otherwise in a review of the capital structure of amalgamated TGI, treat, as the appropriate common equity component in the capital structure of amalgamated TGI, the total of

(a) the appropriate common equity component allowed in the capital structure of TGI by order G-14-06, plus

(b) the differential.

Treatment of return on equity

16 (1) In this section:

"benchmark" means, for any year, the return on equity approved by the commission for that year for a benchmark low risk utility;

"differential" means the positive difference between

(a) the weighted average, based on the relative rate bases of TGI and TGS, of

(i) the approved return on equity of TGI that would have been allowed for ratemaking purposes in 2007 if the amalgamation of TGI and TGS had not occurred, and

(ii) the approved return on equity of TGS that would have been allowed for ratemaking purposes in 2007 if the amalgamation of TGI and TGS had not occurred, and

(b) the approved return on equity of TGI that would have been allowed for ratemaking purposes in 2007 if the amalgamation of TGI and TGS had not occurred.

(2) For the purpose of regulating and fixing rates for amalgamated TGI, the commission must treat, as the approved return on equity for amalgamated TGI in any year, the benchmark applicable to that year plus the differential.

Conflict

17 Nothing in this Special Direction affects Special Direction 1510 except that, if there is a conflict between this Special Direction and Special Direction 1510, this Special Direction prevails.

Expiry of special direction

18 This Special Direction ceases to have any application when Special Direction 1510 ceases to have any application.

SCHEDULE "B"
AMENDMENT TO SPECIAL DIRECTION 1510

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 767 *, Approved and Ordered* NOV – 2 2006

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that effective January 1, 2007, the Vancouver Island Natural Gas Pipeline Special Direction issued to the British Columbia Utilities Commission by Order in Council 1510/95 is amended

(a) by repealing the definitions of "Rate Stabilization Facility", "Rate Stabilization Facility Continuation Agreement" ***and*** "Squamish Rate Stabilization Agreement",

(b) by repealing sections 3.1 (d), 3.3 and 3.8,

(c) in section 3.7 by striking out ", 3.3", ***and***

(d) by repealing Part 5.

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Vancouver Island Natural Gas Pipeline Act*, R.S.B.C. 1996, c. 474, s. 7 (3) and (4)

Other (specify):-

September 27, 2006

934/2006/7

SCHEDULE "C"
REGULATION STATING THAT SECTION 53 OF THE *UTILITIES COMMISSION ACT* DOES NOT APPLY IN RESPECT OF TGS OR TGI IN RELATION TO AN AMALGAMATION OF THOSE TWO CORPORATIONS

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 766 *, Approved and Ordered* NOV - 2 2006

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that section 53 of the *Utilities Commission Act* does not apply in respect of Terasen Gas (Squamish) Inc. or Terasen Gas Inc. in relation to an amalgamation of those 2 corporations.

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Vancouver Island Natural Gas Pipeline Act*, R.S.B.C. 1996, c. 474, s. 7 (2)

Other (specify):-

September 27, 2006

936 /2006/7

Attachment 111.1

October 2006

Contact	Phone
New York	
Edward Tan	1.212.553.1653
Sharon Roberts	
Mihoko Manabe	
John Diaz	
Toronto	
Allan McLean	1.416.214.1635

North American Regulated Gas Distribution Industry (Local Distribution Companies)

Summary

The purpose of this methodology is to provide investors and other interested parties with a clear understanding of how Moody's assigns ratings to issuers and their obligations in the North American local gas distribution (LDC) sector. Our goal is to help the market understand the factors we consider most important for this sector and how they map to specific rating outcomes. Readers should be able to use this report to gauge a company's ratings within two notches.

This rating methodology covers 30 gas utilities in North America (Canada and the United States) all of whom are regulated by their provincial, state or municipal utility commissions. These are relatively small companies that are limited to a particular franchise territory and which ordinarily would not carry investment grade ratings were they not protected through regulation and assured the certainty of a positive gross margin in exchange for the public expectation of a reliable and safe gas distribution service.

Overall, Moody's analysis of gas utility companies focuses on the following core rating factors:

1. Sustainable Profitability
2. Regulatory Support
3. Ring Fencing
4. Financial Strength and Flexibility

In addition Moody's analyzes factors that are common across all industries such as liquidity, corporate governance, event risk, and legal structure.

Moody's Investors Service
Global Credit Research

About the Rated Universe

The focus of this rating methodology is on the "pure" gas LDCs in North America. We note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas utilities owned by parent holding companies that have other non-regulated businesses.

It is anticipated that a separate rating methodology will be forthcoming that would govern the ratings of such "diversified" gas companies including those that may have expanded through non-utility subsidiaries into other non-LDC businesses such as sales of unregulated electric power and gas contracts (energy marketing), gas pipeline transmission and storage, gas gathering and processing, exploration and production, energy trading or businesses that are non-energy related activities (e.g. real estate development or underground construction services).

Additionally, a third rating methodology would also be forthcoming for the gas pipeline companies, completing the three sub-sectors that make up the largely regulated natural gas transmission and distribution industry in North America.

In all Moody's rates 30 companies in the pure gas LDC sector in North America with EBITDA ranging from US$ 32 million to US$ 681 million and total assets ranging from US$ 382 million to US$ 5,974 million. The rated universe stretches from the east coast to the west and ranges in complexity from utilities with jurisdiction in a single state to those with multiple state jurisdictions (such as Atmos Energy Corporation, which has utility operations in 12 states).

Industry Overview

The guiding principle behind gas LDCs is that they are regulated entities within their jurisdictions and are expected to conform to the regulatory framework established by their regulators. The regulatory framework may specify a pre-approved level of capitalization, return on equity, the pass-through of certain cost components and the recognition of a specified level of regulated assets within the base rates established for customers, and the setting of a depreciation schedule based on the average life of plant and equipment. In Canada, regulators may operate at the provincial level. In the United States they might operate at the state or municipal level. As these companies are regulated by local authorities, there are tremendous variances in regulatory frameworks, some more favorable to the utility companies than others.

Allowed rates of return on equity are generally modest (ranging from 9%-12% in most cases depending on cost of capital). This creates certain tradeoffs that are meant to ensure a safe and reliable public service in return for stable and predictable levels of income and cash flow.

HIGHLY SEASONAL DEMAND AND WORKING CAPITAL REQUIREMENTS

The gas distribution business in North America is generally highly seasonal and sensitive to weather variations from one year to another. The vast majority of earnings are derived during the winter heating season (typically, the five months from November through March). In the summer months LDCs usually break even or lose money.

In addition, LDCs are typically subject to vast swings in working capital requirements, with the build-up of natural gas inventory in underground storages occurring during late spring and early summer, reaching a peak in November/December and falling during the course of the winter as gas is consumed. Accounts receivables begin to build in November and generally peak in late December or January. The buildup of short-term debt to meet seasonal working capital needs follows the same winter inventory build-up and accounts receivables financing pattern, with many LDCs completely out of short-term debt by April/May.

In an attempt to standardize the measure of heating days in the year, the industry has adopted the use of "heating degree days," commonly defined as the extent to which the daily average temperature falls below 65 degrees Fahrenheit, (generally assumed to be the point at which individuals would typically heat their homes). The number of heating degree days in a given year are compared against a historical "norm" specified by a regulatory commission in a specific jurisdiction to establish the degree of normalcy within a time frame. This time frame can range anywhere from 10 to 30 years, depending on the formulation approved by the utility regulators.

In some jurisdictions, the earnings impact of weather variations is neutralized through the establishment of weather mitigants as part of fundamental rate design. In its rate applications to the local regulatory commission, the local utility would request protection from weather that is warmer than normal for itself and for its customers when weather is colder than normal. Specifically, weather is compared with current deviations from historical norms as measured in heating degree days. The term often associated with this formal mechanism to compensate a utility for warmer than normal weather (or to compensate a consumer for colder than normal weather) is commonly referred to as a "weather normalization clause" or "WNC."

In jurisdictions that leave LDCs to their own devices, LDCs can either go "naked," or they can purchase weather derivatives or weather insurance to mitigate the effects of margin variations caused by fluctuating weather conditions.

PASS-THROUGH OF NATURAL GAS PRICES

In addition to the fact that gas LDCs are subject to regulation by local authorities, they also operate under the premise that their fixed and variable operatiing costs are borne by their firm demand customers (usually residential and commercial) who use gas for space heating, cooking, or a combination of both. Under the terms of the LDC operating structure, the LDC is not expected to assume the commodity risk of gas, but is able to pass this cost through to customers in monthly bills. Depending on the gas prices at any given time, the commodity price component of a residential customer's monthly bill could be as high as 80%. The remaining 20% would be the LDC's charge for operating and investing in the infrastructure of its gas distribution system (which are, primarily, its fixed costs of operation).

With the advent of third-party gas commodity marketers, this commodity charge is often provided by gas suppliers to consumers utilizing the LDC's gas delivery network. Under this mechanism of "distribution only" charges, the LDC can sometimes use the gas marketer to bill for its 20% of distribution charges, thereby transferring bad debt and risk of non-collection to the gas marketer. More often however, the LDC bills customers for both the gas marketer's commodity supply charges as well as its own delivery charge, retaining bad debt on its own books.

In several jurisdictions, utility regulators have granted LDCs a "bad debt" tracker, which allows them to recover the costs of non-collection via their customers' rate bases or as part of the PGA (purchase gas adjustment clause). Some states such as Pennsylvania and Tennessee have increased the amount of real-time bad debt that could be passed-through to the customer and are also allowing delivery termination for non-paying or delinquent customers to protect the margins of the LDC.

STABLE AND PREDICTABLE EARNINGS AND CASH FLOW

If weather variations are largely mitigated, cost of gas is a pass-though commodity cost, and regulators permit the company to recover its cost of investment and other operating costs for maintaining the gas distribution system, the earnings of the LDC should, theoretically, be largely predictable and cash flows should be stable year after year.

In reality however, LDCs' earnings are not stable, as customers continually find ways to conserve on heating bills, to purchase more efficient appliances or to build better insulated homes. All of these measures result in gas "conservation" and diminishing earnings (again, revenues are largely dependent on the volume of gas consumed). In areas of high growth — i.e. where the customer base is increasing at rates in excess of 3% p.a. — there is also the added pressure of rising operating and maintenance expenditures as well as the need to catch up with lagging capital investment recoveries. These pressures, coupled with rising cost structures and a volatile energy environment oftentimes require an LDC to file more frequent rate cases requesting cost recoveries or changes in fundamental rate design to account for secular changes in consumer behavior patterns that affect the operating margins of the gas utility.

Key Ratings Issues Going Into the Next Decade

The key rating issues affecting the near and medium term fall into three general areas:

- Rising gas prices
- The push for conservation
- The rise of mergers and acquisitions

RISING GAS PRICES

Gas prices follow many of the pressures that bear on oil prices, but also demonstrate characteristics of their own. Historically, North America was an abundant producer of natural gas. What the US could not supply from its own gas fields could be obtained reliably from Canada. Over the years, Canada has been consuming more of its gas, both to supply its own citizens' needs and to recover heavy oil lodged in sand formations where gas is burned underground to facilitate the oil recovery mechanism.

Also affecting the industry is a change in the pattern of the summer lull in gas prices. This is attributable to the fact that the electric power industry has been building new generation plants fueled by gas, mainly because of gas' clean-combustion characteristics. The vast majority of new electric generating plants built in the past few years have been fired by gas and these power plants burn more summer gas to generate electricity to meet cooling demands. As a consequence, the traditional lull in summer gas prices has become less reliable with the increased volatility in gas commodity pricing.

Rising demand for natural gas has also diminished the supply cushion to the point that hurricane disruptions such as those in the gas producing areas of the Gulf of Mexico in 2005 created logistical delivery disruptions to certain LDCs in the southeastern portion of the US. This confluence of increased gas demand and supply constraints is likely to maintain upward price pressure on natural gas prices over the medium term.

High gas prices have the undesirable effect of causing a rise in bad debt expenses and uncollectible receivables for many gas utilities, creating yet more need for rate design improvements.

THE PUSH FOR CONSERVATION

Another consequence of high gas prices is consumer motivation to burn less gas when possible. We have observed an impetus to reduce consumption in response to rising prices over the past decade. In North America this trend is most noticeable within the most rapidly growing home building areas, where homes are being built with better insulation. Another impetus for conservation is rising gas prices and warmer weather, where it is relatively easy for homeowners to turn-down the thermostat for extended periods of time, reducing gas margins earned by LDCs that are dependent on volumetric gas consumption for cost recoveries.

Conservation is an important component in balancing the region's gas supply and demand equation, but under traditional regulatory frameworks in many jurisdictions, few gas utilities have the incentive to encourage gas conservation or promote education in gas usage efficiencies among their customers. With the likelihood that gas prices will remain high and volatile, conservation will likely become a more formidable influence on gas consumption in the residential and commercial customer segments going forward.

In the US, utility commissioners in various states differ in their approaches to allowing their gas utilities to recover lost margins attributable to conservation-driven variations in consumption. Commissions with more supportive regulatory frameworks tend to allow mechanisms for revenue recoveries and their utilities generally have stronger financial profiles.

As more LDCs become aware of the impact that conservation initiatives have on their customers' gas usage and their own profitability, more are considering applying for the appropriate rate design changes. To do this, however, they must first build understanding and support at the grassroots level. Overall, utility rate designs that compensate gas LDCs for conservation-based margin losses (as with variations due to weather), should help to stabilize utilities' credit metrics and credit ratings. Utilities with these ratemaking mechanisms also tend to carry higher credit ratings.

THE RISE OF MERGERS AND ACQUSITIONS

With the repeal of the Public Utility Holding Company Act (PUHCA) in the US (February 2006) companies are finding fewer obstacles to mergers across state lines. Companies seeking to expand their service territories are now finding it easier to bid for companies seeking an opportunity to cash out (as price multiples are currently attractive for sellers in this industry).

The pace of industry consolidation as well as the introduction of new players could accelerate beyond 2006. From a credit standpoint, however, we note that mergers and acquisitions usually entail taking on more debt, attempts to create new operating synergies, and the need to apply for further rate relief from regulators. Previous periods of heightened mergers and acquisition activity were typically associated with increased numbers of ratings downgrades, as LDC debt levels and operating costs rose and rate recoveries lagged. While it is still early to predict whether past performance will repeat itself in the current merger-driven environment, the denigration of credit metrics remains a possibility.

In This Methodology

To explain Moody's approach to rating gas utility companies, we take the reader through the following steps:

IDENTIFICATION OF KEY RATING FACTORS

To determine the rating of a gas utility company we focus on the following factors:

1. **Sustainable Profitability**
   - Return on Equity
   - EBIT to Customer Base
2. **Regulatory Support**
   - Regulatory Support and Relationship
3. **Ring Fencing**
   - Ring Fencing
4. **Financial Strength and Flexibility**
   - EBIT/Interest
   - Retained Cash Flow/Debt
   - Debt to Book Capitalization (excluding goodwill)
   - Free Cash Flow/Funds from Operations

MEASUREMENT OF THE KEY RATING FACTORS

For each of the core factors cited, we present a set of metrics or "sub-factors" that enable the reader to determine exactly how we measure this factor. Each of the core factors is comprised of between one and four sub-factors, each of which are mapped to a rating or score. For example, we consider four different financial metrics within the Financial Strength and Flexibility Factor.

In total this rating methodology incorporates eight sub-factors. Where possible, we provide quantitative metrics derived from a company's financial statements. For some factors, however, non-statistical observation is necessary to determine the appropriate results. For each of the eight metrics, we assign a weight based on relative importance.[1]

Moody's applies a total weighting of 20% for non-financial observations and 80% for financial. (However, we weigh some sub-factors more heavily than others, as some sub-factors such as the ROE (return on equity) and the ones for Financial Strength and Flexibility weigh more heavily in determining the relative risk of a particular LDC in comparison with its peers). This is because, while regulatory design and support may differ from jurisdiction to jurisdiction, the financial metrics do not. This renders them more easily comparable across political boundaries and more quantifiable. Financial observations also tend to be lagging indicators, as they come at the end of a fiscal reporting period and serve as the final scorecard for the issuer. The two non-financial sub-factors tend to be less definitive and are more subject to interpretation. Applying the sub-factor weightings and scoring the rating assignment for each sub-factor in this manner results in ratings that track our assigned ratings within one or two notches in 93% of the cases.

While Moody's outlooks are forward looking, the rating process does make extensive use of historic financial statements. Historic results help us understand the pattern of a company's results and how it compares to peers. They also provide perspective, helping to ensure that estimated future results are grounded in reality. This document makes use of historic data primarily. However, if an LDC is undergoing a rate case or fundamental business transformation — negating the usefulness of past performance as a guide to future credit standing — we use projected financial results instead.

Where historical financial results are used, metrics are based on an average of the most recent three years. The 2003 through 2005 periods provide a good cross-section of the peaks and troughs that characterize individual company performance over a normalized period.

Where projected financial results are used, metrics are based on an average of the 2006 through 2008 periods, or in some cases, 2007 through 2009, depending on the implementation dates of rate increases or realization of expected merger combinations.

All measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts including under-funded pension obligations, recurring operating leases, and off-balance sheet commitments and contingencies.[2] Moody's Credit Opinion key indicator ratios will also incorporate these standard adjustments.

MAPPING OUR METRICS TO RATING CATEGORIES

After identifying the measurements for each factor, the potential outcomes for each of the eight factors/sub-factors are mapped to a Moody's rating category (i.e. Aaa, Aa, A, Baa, Ba, B, Caa). For example, we specify what level of ROE is generally acceptable for an Aa credit versus an A credit. We provide a range or description for each of the measurement criteria.[3]

COMPANY MAPPING/OUTLIER DISCUSSION

We next assign a rating to each company in our rated universe for each factor. We also show how this rating compares to the company's actual assigned rating. The results of this mapping appear in a summary table located in Appendix B, as well as in the results section under each factor.

We recognize that any given company may perform higher or lower on a specific factor than its actual rating level. These companies are identified as "outliers" for that factor. A company whose performance on a specific factor is more than two rating notches higher than its actual rating is deemed a positive outlier for that factor. A company whose performance is more than two notches below is deemed a negative outlier. We highlight those companies whose factor mapping is more than two notches higher or lower than its rating and offer a discussion of the general reasons for outliers within a given factor.

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1. *See Appendices A and B for a summary of sub-factors and weightings for each sub-factor.*
2. Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations — Part I *(US/Canadian GAAP, February, 2006).*
3. *See Appendix D for non-financial sub-factor definitions.*

DETERMINING THE FINAL RATING

To determine the overall rating, each of the eight assigned sub-factor ratings is converted into a numeric value based on the following scale.

1	3	6	9	12	15	18
Aaa	Aa	A	Baa	Ba	B	Caa

Each sub-factor's numeric value is multiplied by an assigned weight (refer to the table below and/or Appendices A and B, for weights), and then summed. For information purposes, the table below also shows sub-totals and how much weight is given to each broad rating factor.

Factor	Sub-Factor	Weighting	Cumulative Weighting of the Relevant Sub-Factors
Sustainable Profitability	ROE	15%	20%
	EBIT/Customer Base	5%	
Regulatory Support	Regulatory Support	10%	10%
Ring Fencing	Ring-Fencing	10%	10%
Financial Strength and Flexibility	EBIT/Interest	15%	60%
	RCF/Debt	15%	
	Debt/Book Capitalization	15%	
	Free Cash Flow/FFO	15%	
Total Weighting		**100%**	

The total is then mapped to the table below, and an overall alpha-numeric rating is assigned based on where the score falls in the range. The outcome provides a good correlation, with indicated ratings falling at or two notches away from actual ratings.

Indicated Rating	Overall Score
Aaa	**= 1**
Aa	> 1 < 4.5
A	>= 4.5 < 7.5
Baa	>= 7.5 < 10.5
Ba	>= 10.5 < 13.5
B	>= 13.5 < 16.5
Caa	>= 16.5

The entire array of scores and mappings for each of the LDC companies is shown in Appendix B.

Factor Discussions

FACTOR 1: SUSTAINABLE PROFITABILITY

Why It Matters

Two subfactors provide good indications of a firm's ability to remain profitable and efficient despite the inherent volatility associated with the sector:

- **Return on equity (ROE)**, which is calculated for each year by taking a company's profitability in a given year and dividing it by an average equity of the current and previous year end. ROE serves as barometer of a company's general level of profitability — and when calculated over a period of years, serves as an indicator of its ability to sustain its profitability — and provides a good starting point for understanding the overall efficiency of the operations of the company.
- **Operating Income (EBIT)** relative to customer base provides another indicator of a gas utility's overall operating profitability relative to the number of customers being serviced. The higher this figure, the more each customer contributes to the company's "bottom-line." For purposes of this calculation, only firm demand customers of the residential and commercial categories are included, as industrial customers often have alternate

sources of fuel and are the first to be cut off by a utility in the event of gas pro-rationing (allocation as a percentage of available supply) or shortage.

The former calculates returns on a GAAP basis and the latter serves as a measure of overall operating efficiency. When an average of three years is used as the comparable period, these indicators reveal the company's relative profitability and ability to maintain this profitability and efficiency on a sustainable basis.

LDCs may differ in their rate design, the effectiveness, and the timeliness of rate design, but they ultimately culminate in an ROE scorecard that is an irrefutable indicator of the profitability that the firm has achieved (or in the case of projected figures resulting from a rate case filing or decision, projected profitability) given the business environment in which it operates. Similarly, the EBIT/customer base measures the relative operating efficiency of the company in achieving these operating results.

Among the risk factors reflected in ROE are the presence and effectiveness of the LDC's weather normalization clause (WNC), its ability to increase earnings despite customer gas conservation, the ability of the firm to pass through bad debt expenses, to true-up for underfunded pension liabilities, the frequency and degree of price adjustments for gas cost purchase adjustments, the ability to pass along financial and derivative hedging costs to consumers, to reimburse itself for environmental remediation expenditures, to use forward year test data in factoring in capital expenditure cost recoveries, and its ability to cover rising O&M (operating and maintenance) expenditures. The firm's effectiveness in dealing with these risks is distilled into an ROE calculation. Over time, this calculation provides a profile of the company's ability to generate consistent earnings that are capable of covering the cost of doing business and capable of doing so over an extended period of time. It also provides a benchmark measure of efficiency relative to other LDCs with similar business profiles.

It should be noted that in the use of ROE, the measure of profitability is indifferent as to whether an LDC employs multiple approaches to shielding itself from gas commodity price volatility (such as through use of various forms of financial derivatives) or if it relies primarily on underground gas inventory storage or long-term pipeline deliveries at fixed costs. Similarly, it does not impose a requirement that the LDC have a WNC in place to protect its gas margins against warmer than normal winters, as the company could achieve similar results by employing its own form of weather mitigants through the purchase of weather insurance or derivatives. The importance of achieving a desired target ROE is the fact that it signals management's effectiveness in employing all possible measures to achieve its business goals.

That said, the better the quality of an LDC's rate design or effectiveness in generating operating profits, the greater and more consistent its ROE. Very few businesses are assured a stable and consistent return on their capital by a regulatory body, but LDCs are (in theory, at least). To the extent they employ highly effective rate designs and business solutions in mitigating the known risk factors in the business, the better the ROE and efficiency of its operations.

Despite wide variations in individual utility rate designs therefore, ROE and EBIT/Customer Base appear to capture the level of profitability and efficiency in an LDC's operations and reflect its ability to generate profits over a sustainable period of time.

We note that profitability (ROE), operating income to customer base (EBIT/residential+commercial customers), interest coverage, retained cash flow to debt, debt to capital and free cash flow to funds from operation are the credit metrics that contribute the most to differentiating the stronger LDCs from the weaker ones. These also tend to be the "lagging" indicators as financial results are only available after the close of a fiscal quarter. Thus, they serve as a report card for the close of a given financial period, after all the events of the period have already transpired and all the initiatives of management are either completed or left undone.

Measurement metrics for this factor are as follows:

- **ROE** — profitability in a given year / average equity of the current and previous year.
  Weighting: 15%
- **(EBIT) to Customer Base:** For purposes of this calculation, only firm demand customers of the residential and commercial categories are included, as industrial customers often have alternate sources of fuel and are the first to be cut off by a utility in the event of gas pro-rationing (allocation as a percentage of available supply) or shortage.
  Weighting: 5%

Factor Mapping: Sustainable Profitability

	Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
Return on Equity	20%	15%	> 19%	14 – 19%	9 – 14%	5 – 9%	2 – 5%	0 – 2%	< 0%
EBIT/# of Residential & Commercial Customers		5%	> $350	$250 - $350	$150 – $250	$100 – $150	$50 – $100	$0 – $50	< $0

Company Mapping Results: Sustainable Profitability

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio
Alabama Gas Corporation	A1	14 – 19%	Aa	$150 – $250	A
New Jersey Natural Gas Company (Sec Aa3)	A1	9 – 14%	A	$150 – $250	A
Wisconsin Gas	A1	5 – 9%	Baa	$100 – $150	Baa
Boston Gas Company	A2	2 – 5 %	Ba	$150 – $250	A
Brooklyn Union Gas	A2	9 – 14%	A	$150 – $250	A
KeySpan Gas East Corporation	A2	9 – 14%	A	$250 – $350	Aa
Northern Illinois Gas	A2	5 – 9%	Baa	$50 – $100	Ba
North Shore Gas Company (Sec A1)	A2	5 – 9%	Baa	$50 – $100	Ba
Peoples Gas Light and Coke Compa (Sec A1)	A2	5 – 9%	Baa	$100 – $150	Baa
Public Service Co. of North Caro	A2	5 – 9%	Baa	$150 – $250	A
Questar Gas Company	A2	9 – 14%	A	$50 – $100	Ba
Southern California Gas Company	A2	14 – 19%	Aa	$50 – $100	Ba
Washington Gas Light Company	A2	9 – 14%	A	$150 – $250	A
Terasen Gas Inc.	A3	9 – 14%	A	>$350	Aaa
Colonial Gas Company (Sec A2)	A3	2 – 5 %	Ba	$250 – $350	Aa
Northwest Natural Gas Company	A3	9 – 14%	A	$150 – $250	A
Piedmont Natural Gas Company, In	A3	9 – 14%	A	$150 – $250	A
Connecticut Natural Gas	A3	2 – 5 %	Ba	$250 – $350	Aa
UGI Utilities, Inc.	A3	14 – 19%	Aa	$250 – $350	Aa
AGL Resources Inc.	Baa1	14 – 19%	Aa	$150 – $250	A
Cascade Natural Gas Corp.	Baa1	9 – 14%	A	$100 – $150	Baa
Indiana Gas Company, Inc.	Baa1	5 – 9%	Baa	$100 – $150	Baa
Laclede Gas Company	Baa1	9 – 14%	A	$100 – $150	Baa
Southern Connecticut Gas (Sec A3))	Baa1	2 – 5 %	Ba	$150 – $250	A
Laclede Group, Inc. (The)	Baa2	9 – 14%	A	$100 – $150	Baa
South Jersey Gas Company	Baa2	9 – 14%	A	$150 – $250	A
Yankee Gas	Baa2	2 – 5 %	Ba	$150 – $250	A
Atmos Energy Corporation	Baa3	9 – 14%	A	$50 – $100	Ba
Southwest Gas Corporation	Baa3	5 – 9%	Baa	$50 – $100	Ba
SEMCO Energy, Inc.	Ba2	<0%	Caa	$100 – $150	Baa

Positive Outlier
Negative Outlier

Observations and Outliers

ROE

Among the negative outliers are Boston Gas and Colonial Gas, two of six natural gas distribution companies owned by KeySpan Corp. Their low ROE reflects push down accounting relating to KeySpan's acquisition of Eastern Enterprises, whereby a portion of the acquisition debt and goodwill issued by the parent have been allocated to Boston Gas and Colonial Gas. The debt and parent financing of working capital and gas inventory through the utility money pool has resulted in noticeably increased debt and interest expense levels. Additionally, National Grid's recently announced plan to acquire Keyspan raises the possibility of an additional debt servicing burden being "pushed down" to these subsidiaries. The low ROE also reflects the lower efficiency of the rate design in these KeySpan subsidiaries. The lack of

weather mitigation and conservation in the company's rate design leaves it vulnerable to weather and conservation exposure, which are being mitigated in part through the purchase of weather derivatives.

The Connecticut LDCs of Connecticut Natural Gas, Southern Connecticut Gas and Yankee Gas also have low ROEs relative to their assigned ratings, reflecting relatively poor regulatory support from the state commission on weather and conservation protections, and the ability to pass financial hedging costs to rate-payers as a means to mitigate gas price volatility. These LDCs are also smaller subsidiaries within larger electric power utility operations that may require additional forms of parental support for the LDCs.

In the case of Wisconsin Gas the company was approved for a rate base increase, effective January 2006, for an approved ROE of 11.2%, but historical returns had eroded because of a five-year rate freeze.

Among the positive outliers are UGI Utilities, AGL Resources and Atmos. Although UGI has a high ROE relative to its peer group, the overall rating is suppressed because of its affiliation with non-investment grade subsidiaries of the parent.

In the case of AGL and Atmos, the diversified earnings of the group include income from operations such as energy services. These tend to boost the group's returns even though the combined risk may indicate a less stable and predictable earnings stream.

EBIT to Customer Base

Northern Illinois Gas and North Shore Gas Company are negative outliers in this operating efficiency ratio, as they have been suffering from regulatory lag. However, the recent rate increase in the case of Northern Illinois Gas could help narrow the gap in its performance going forward.

On the other extreme, UGI appears to be a very efficient operator and is a positive outlier from a customer base standpoint. Although UGI has strong operating income (being supported by a higher than average customer growth rate — mostly attributable to organic growth), the overall rating is suppressed because of its affiliation with non-investment grade subsidiaries of the parent.

FACTOR 2: REGULATORY SUPPORT

Why It Matters

The fact that LDCs are subject to regulation by local authorities has a direct bearing on the success of their business operations. It is difficult for utilities to function without good community relations, as they depend on their local regulators and on the public's understanding to obtain the rate relief and cost recovery necessary for a gas distribution system's investments.

Of particular importance, regulatory requirements are often delineated not by law or by prescribed statutory requirement or ruling but rather by the expectation that traditional practices will continue and that LDCs — particularly the older and more established ones — will continue to act within established boundaries and in accordance with past practice. This necessitates a strong relationship with regulators who are, ideally, supportive.

Thus, when the regulatory relationship is strong and cooperative, utilities are able to engage in active dialogue with regulatory commissioners and staff to find mutually acceptable solutions to utility problems (such as rising account delinquencies in periods of gas shortages and price increases) or to educate customers about key initiatives such as gas conservation. In a strong relationship, the commission staff might also serve as a technical advisor to the utility commission in facilitating constructive discussions with the company — as opposed to playing the role of "consumer advocate" and countering LDC initiatives.

One very important component of the utility/regulator relationship is the ability of the utility to recoup allowed expenses in a timely manner and its ability to earn its fully-allowed rate of return (without having to file continuously for new rate cases).

Within this metric we also include the utility's relationship — both perceived and actual with the public and its approach to issues of safety, reliability and integrity.

This metric thus helps to define credit impact of the established operational "norms" and the operating framework. It is conceivable for a utility to maintain an investment grade rating with only limited support from its regulators if it has capable management that is able to find alternatives and solutions for its business needs, but the support of regulators on most matters of economic importance enable a company to operate with far more effectiveness. We note that, included in the definition of "regulatory environment" are regulatory staff, commission, interveners, consumer advocates and the public at large.

Measurement metrics for this factor are as follows:

- **Quality of Regulatory Support:** The regulatory relationship is measured on a scale from "Exceptional/ Proactive" to "Inadequate/Weak." To assess the quality of the regulatory support we examine the strength of the regulatory relationship. This will include the speed and degree of willingness with which the regulatory commission approves requests for rate increases, approves and encourages rate design modifications that serve to help a utility recoup its operating and capital investment costs and whether regulators enable utilities to recoup such costs in a timely manner.
  Weighting: 10%

Notes on Measurement Criteria

This sub-factor is important and will have a direct bearing on the ultimate credit rating of the LDC, although it lacks the finality of the more formulaic financial sub-factors (regulatory decisions may be modified or reversed by future regulators or a court action, whereas ROE results, for example, cannot). Because regulatory support is often subject to interpretation and change over time as the actions and views of participants change, it is weighed less heavily than are financial metrics.

Factor Mapping: Regulatory Support

Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
10%	10%	*Exceptional Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission always willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Utility Commission grants all rate design features to allow LDC to recover costs on a complete and timely basis.	*Very Good Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission highly willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Rate design is near "bulletproof" cover for LDC risks. Requested rate increases tend to be approved in less than 9 months.	*Good Support* by Utility Commission to allow LDCs to amend rate designs. Company gets good support in proposing new solutions to deal with common utility problems such as conservation and weather variables; Differences between LDCs and utility commission are likely to be resolved. Rate filings tend to be approved under 12 months.	*Reasonable support* from Utility Commission to allow LDCs to recoup allowed expenses; Company gets some support in proposing new solutions to deal with common utility problems such as conservation and weather issues; Differences between LDCs and Utility Commission are reasonably resolved in a timely manner and rate cases tend to be approved in 12 – 15 months with at least 50% of LDC's target requests being granted.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner and/or staff tends to play the role of "consumer advocate" that often counters proposals or initiatives advanced by the LDC. Cases often take over 15 months to resolve or LDC is frozen out of rate filings for over 18 months.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner often plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC; Company is seldom involved with working on special task forces to deal with issues of rising account delinquencies or educating customers on conservation or warm weather issues. Utility suffers from increasing regulatory lag and lacks rate relief necessary to earn allowed ROE.	*Inadequate and weak support* from Utility Commission to allow LDCs to recoup allowed expenses. Utility commissioner always plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC; Company is hardly ever involved with working on special task forces to deal with issues of rising concern to utility or customers. Unsupportive commission/ state legislature or consumer base. Utility can't earn allowed ROE.

Company Mapping Results: Regulatory Support

Issuer Name	Current Senior Unsecured Rating	Indicated Rating: Regulatory Support
Alabama Gas Corporation	A1	Aaa
New Jersey Natural Gas Company (Sec Aa3)	A1	Aaa
Wisconsin Gas	A1	Baa
Boston Gas Company	A2	Baa
Brooklyn Union Gas	A2	Baa
KeySpan Gas East Corporation	A2	Baa
Northern Illinois Gas	A2	Baa
North Shore Gas Company (Sec A1)	A2	Ba
Peoples Gas Light and Coke Compa (Sec A1)	A2	Ba
Public Service Co. of North Caro	A2	Aaa
Questar Gas Company	A2	Ba
Southern California Gas Company	A2	A
Washington Gas Light Company	A2	Baa
Terasen Gas Inc.	A3	Aa
Colonial Gas Company (Sec A2)	A3	Baa
Northwest Natural Gas Company	A3	Aaa
Piedmont Natural Gas Company, In	A3	Aaa
Connecticut Natural Gas	A3	Ba
UGI Utilities, Inc.	A3	Baa
AGL Resources Inc.	Baa1	Baa
Cascade Natural Gas Corp.	Baa1	Baa
Indiana Gas Company, Inc.	Baa1	Aa
Laclede Gas Company	Baa1	Aa
Southern Connecticut Gas (Sec A3))	Baa1	Baa
Laclede Group, Inc. (The)	Baa2	Aa
South Jersey Gas Company	Baa2	Aa
Yankee Gas	Baa2	Ba
Atmos Energy Corporation	Baa3	Baa
Southwest Gas Corporation	Baa3	Ba
SEMCO Energy, Inc.	Ba2	Ba

Positive Outlier
Negative Outlier

FACTOR 3: RING FENCING

Why it Matters

- **Ring Fencing:** Many LDCs are owned by diversified energy companies engaged in non-regulated activities. For this reason, the degree to which an LDC is "ring-fenced" will have an impact on the quality and degree of protection afforded to the utility's assets and operating cash flows. Whether imposed by regulators, lenders, or by the parent company (self imposed) the ring-fencing must assure that the utility is self-standing and protected from non-regulatory businesses of the diversified parent group[4]. This is a common objective among regulators, lenders and consumers alike. Also, as in the case with weather mitigants, Moody's does not insist that there be explicit written statutes requiring the gas utility to be properly ring-fenced for the utility to be highly rated, as long as this is accomplished in an effective manner through other means.

  Among the contributors to a well ring-fenced utility are limitations on inter-company loans and advances to non-regulated affiliates or prohibitions on the commingling of funds through participation in diversified corporate money pools. These are important in ascertaining that the utility's operating assets and capital expenditures are justifiable to utility ratepayers.

  Other contributors to strong ring fencing are legal or regulatory requirements stipulating maximum leverage ratios for the LDC and requirements that an LDC remain investment-grade to preserve its service

4. *The expectation that non-regulated expenses incurred by affiliates engaged in other businesses will not be passed onto the utility (which would then attempt to seek recovery from its consumers) is intrinsic to the concept of ring fencing. For example, a diversified gas company with a gas trading operation is expected to deal with its regulated utility at arm's length. It is not expected that the company will allow the trading company to determine which entity should receive the best price quotes for gas purchase transactions or which should be chosen to book trading losses.*

franchise. By placing a limitation on leverage, regulators or lenders are implicitly limiting the level of dividends that a diversified parent company might extract from its utility, and discouraging the utility from using its balance sheet to raise debt for the benefit of non-utility affiliates or its diversified parent.

The utility's payment of dividends in excess of what the parent company may require for its public shareholders could also serve as an indication of poor ring fencing, as the surplus funds being paid as dividends by the utility could be viewed as a form of cash support for the parent company's non-utility affiliates. Well ring-fenced utilities typically raise their own funds and handle their own bank accounts, with non-utility affiliates establishing their own credit facilities and funding requirements separate and independent from the utility.

Weighting: 10%

- Less obvious, but also important are the proven resolve of management or a utility's board in erecting operating barriers that isolate the utility from its non-regulated affiliates. This might include, for example, dedicating separate utility gas purchasing agents from the group's energy trading arm or locating utility personnel at separate premises from those of the non-utility affiliates. These good corporate governance attributes are implied in having good ring-fencing measures.

  Utilities sometimes establish their own boards of directors, especially within a larger and more diversified company to ensure that their assets, cash flows and operating funds are properly separated and that attempts by the parent to distribute dividends to the holding company are fair and justified. Any weak corporate governance would typically become evident in reviewing a utility's ring fencing quality and manifest itself through lax policies and procedures in operations as well as in financial dealings, record-keeping and internal controls. Corporate governance therefore, is a related indicator for ring fencing quality.

  While such efforts as creating a permanent body to ensure the operating integrity of the utility could add to the strength of the ring fencing provisions, it is a further indicator that the utility stands on its own and is governed by a board that looks after its interest first rather than using the utility to advance the goals of the parent's diversified group. Ultimately, such efforts can enhance the utility's independent operating performance and credit rating.

  The utility's board may also require that it obtain its own credit facilities, issue its own bonds and only guaranty activities directly related to providing core utility services. Under this framework, the utility serves as its own profit center and allocates any expenses incurred on behalf of non-utility sister companies back to those affiliates for recovery, rather than burdening its own operating staff and the utility ratepayers.

Measurement metrics for this factor are as follows:

- **Ring Fencing:** This metric is assessed on a scale of "excellent ring fencing isolating utility from non-utility" to "inadequate and weak ring fencing: funds always commingled." In determining the degree of commingling of funds, LDCs range from having their own bank accounts and issuing their own debt and commercial paper to participating in combined cash money pools or engaging in making intercompany loans to non-utility affiliates on a frequent basis). Other indicators that we review for quality of ring fencing include: the level of dividends that are upstreamed by the utility to the parent vs. the parent to the public shareholders, the level of intercompany transactions, the ability of various operating entities to raise their own bank and public financing, the extent of any cross-default provisions or cross-guarantees, the presence of utility financial covenants that would enhance their ring fencing and signs of weak corporate governance.
  Weighting: 10%

Factor Mapping: Ring Fencing

Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
10%	10%	*Excellent* ring-fencing provisions isolating Utility from Non-Utility; No commingling of funds; Utility cash accounts are separated from rest of company; Inter-company loans never permitted between utility and non-utility; No portion of Utility dividend payment to parent ever ends up being allocated to non-utility. Strong	*Very Good* ring-fencing provisions; Utility and Non-Utility highly unlikely to commingle funds; Separate cash program or own utility money pool; Inter-company loans not permitted between utility and non-utility; Utility dividend payment to parent never end up being allocated to non-utility.	*Good* ring-fencing provisions; Utility and Non-Utility are unlikely to commingle funds; Separate utility money pool or utility accounts; Inter-company loans not permitted between utility and non-utility; Utility dividend payment to parent unlikely to be allocated to non-utility.	*Reasonable* ring-fencing provisions; Utility and Non-Utility may need to commingle funds via consolidated corporate money pool; Bond indentures or bank credit agreements may reasonably restrict the utility from financial dealings with non utility; Inter-Company loans between utility and non-utility rare.	*Inadequate* ring-fencing provisions; Utility often participates in corporate cash money pool that includes non-utility and funds are often commingled; Regulators usually do not have a requirement that LDCs remain investment grade. Bond indentures or bank credit agreements may not restrict the utility financial dealings with non- utility.	*Inadequate* ring-fencing provisions; Utility often participates in corporate cash money pool that includes non-utility and funds are generally commingled; No requirement for LDCs to remain investment grade. Bond indentures or bank credit agreements usually do not restrict the utility financial dealings with non- utility. Inter-company loans between utility and non-utility common place.	*Inadequate and weak* ring-fencing provisions; Utility and Non-Utility generally always commingle funds; No requirement for LDCs to remain investment grade; Bonds indentures/ bank agreements never restrict utility financial dealing with non-utility. Inter-company loans between utility and non-utility are common place; Utility dividends to parent may fund non-utility needs.
		Corporate Governance protecting utility interests which are treated as core operation.	Very Good Corporate Governance. May lack formal regulatory or creditor leverage restrictions or IG requirement for utility, but company has strong policy of ring-fencing utility.	Good Corporate Governance of utility	Satisfactory Corporate Governance. Gas utility contributes less than 90% of consolidated group EBIT and may not be primary growth engine.	Inadequate Corporate Governance protection for utility as stand-alone entity.	Inadequate Corporate Governance for utility as a stand alone entity.	Inadequate and weak Corporate Governance of utility interests.

Company Mapping Results: Ring Fencing

Issuer Name	Current Senior Unsecured Rating	Indicated Rating: Ring Fencing
Alabama Gas Corporation	A1	Baa
New Jersey Natural Gas Company (Sec Aa3)	A1	Aaa
Wisconsin Gas	A1	Baa
Boston Gas Company	A2	Baa
Brooklyn Union Gas	A2	Aaa
KeySpan Gas East Corporation	A2	Aaa
Northern Illinois Gas	A2	Baa
North Shore Gas Company (Sec A1)	A2	Baa
Peoples Gas Light and Coke Compa (Sec A1)	A2	Baa
Public Service Co. of North Caro	A2	Aaa
Questar Gas Company	A2	A
Southern California Gas Company	A2	Aaa
Washington Gas Light Company	A2	Aaa
Terasen Gas Inc.	A3	Aa
Colonial Gas Company (Sec A2)	A3	Baa
Northwest Natural Gas Company	A3	Baa
Piedmont Natural Gas Company, In	A3	Aaa
Connecticut Natural Gas	A3	Baa
UGI Utilities, Inc.	A3	A
AGL Resources Inc.	Baa1	Baa
Cascade Natural Gas Corp.	Baa1	Aaa
Indiana Gas Company, Inc.	Baa1	Baa
Laclede Gas Company	Baa1	A
Southern Connecticut Gas (Sec A3))	Baa1	Baa
Laclede Group, Inc. (The)	Baa2	Baa
South Jersey Gas Company	Baa2	Aaa
Yankee Gas	Baa2	Baa
Atmos Energy Corporation	Baa3	Baa
Southwest Gas Corporation	Baa3	Aaa
SEMCO Energy, Inc.	Ba2	Baa

Positive Outlier
Negative Outlier

Observations and Outliers

Ring Fencing

Most of the indicated ring-fencing ratings are compatible with issuer assigned credit ratings. The "Aaa" ring-fencing indicators are typically reserved for those companies whose jurisdictions have established explicit requirements for separation of utility and non-utility businesses, maximum leverage, specific requirements that the LDC remain investment-grade or have placed limitations on dividends to their parent failing certain capitalization requirements. Exceptions might include Washington Gas Light Company, where despite the absence of specific regulatory requirements, the company has a strict policy of not commingling the gas utility funds with those of the non-regulated operations of the parent and the LDC only remits dividends to the parent that are required for distribution to public shareholders, prohibiting its LDC from assisting or supporting the business needs of its non-regulated affiliates.

In the case of Piedmont Natural Gas, Cascade Natural Gas and Southwest Gas Corporation, the utility is the parent company and there is no need for ring-fencing against a diversified non-regulated affiliate.

Negative outlier Alabama Gas results from the LDC having no explicit ring-fencing provisions from regulatory or financing agreements other than broad restrictions under an Alabama state statute.

Regulatory Support

Several "A" rated companies have outstanding regulatory relations and support "Aaa." Some examples include New Jersey Natural Gas Company, Northwest Natural Gas Company and Piedmont Natural Gas Company, where each one of these names have pioneered in the introduction of innovative service concepts and novel rate design concepts such as those for "conservation decoupling" in their respective jurisdictions and all have previously obtained WNC from their

regulators. The regulatory relationship for some of the "Baa" names have also improved to the point where they also scored high in this factor ("Aa"), such as Indiana Gas Company and Laclede Gas Company in Missouri, where these LDCs were the first companies to obtain weather protection mechanisms from their public utility commissions either in the form of formal WNC or through fixed demand charge rate design. Utilities that score high in this factor also tend to be leaders in scoring high on customer satisfaction responses to independent surveys, helping their utility commissioners forge solutions to common utility problems such as dealing with the cost of high gas prices, or providing safety and systems integrity solutions before major problems arise, while maintaining strong community relations.

FACTOR 4: FINANCIAL STRENGTH AND FLEXIBILITY

Why It Matters

Financial strength is an important indicator of an LDC's ability to meet its financial obligations, particularly in light of the volatile nature of the industry's performance[5]. The metrics we use to define this factor include the following:

- **Interest coverage** (EBIT/Interest) is a measure of financial flexibility in an LDC's credit agreement as some lenders require minimum coverage to maintain their credit lines (the concept being that a stable utility should, at a minimum, be able to pay its interest expenses if not amortize its debt over a reasonable time period).

  Interest coverage serves as an indicator of fixed charge coverage. We chose this coverage ratio as it is used in the financial covenants of many LDC bank credit agreements and bond indentures, and is, by extension, both conventional and accessible for comparative purposes. Naturally, the higher this fixed charge coverage, the greater the financial flexibility of the utility.
- **Retained Cash Flow to Debt** (RCF/Debt) is a measure of financial leverage as well as an indicator of the strength of a utility's funds from operations after dividend payments are made to service the debt. It serves as a measure of financial health as well as liquidity to cover debt obligations while also providing a measure of cash available for capital expenditures and to cover working capital needs. RCF/Debt also serves as a measure of leverage relative to operating cash available for debt service.

  The higher the level of retained cash flow relative to debt, the more cash the LDC has after paying dividends to support its capital expenditure programs. The stronger LDCs tend to have sufficient retained cash flow to cover capital expenditure needs, while the weaker ones tend to run cash "deficits" that must be covered through increased equity issuance or debt, or a combination of both. Usually, debt is issued first, followed by occasional equity issuance to meet specific project needs or to strengthen the balance sheet.
- **Debt to Book Capitalization (Excluding Goodwill)** is a more generic measure of financial leverage and has, in the past, been a good barometer with which to gauge the financial flexibility available for a utility to expand and grow in its operations when it has a debt load to service. This measure subtracts goodwill from capitalization because regulators typically do not give credit for premium paid on acquired assets.

  High leverage reduces a firm's operating flexibility not only because it raises interest expense but also because it limits the company's ability to raise additional capital to cushion the impact of poor business conditions. High leverage may also portend the approach of maximum allowed debt capacity under most bank credit agreements, which often set a 65% debt/capitalization borrowing limit for investment grade LDCs.
- **Free Cash Flow as a portion of Funds from Operations** (FCF/FFO) measures the amount of free cash flow as a percentage of funds from operations after dividends are paid, working capital changes are taken into account and capital expenditures are made. While this is a stringent indicator of a utility's cash flexibility, it is a good indicator of cash generating capability and flexibility to deal with unforeseen circumstances or emergencies (gas supply disruptions, production shortages, etc.) — and the accompanying side effect of rapidly rising gas commodity prices — while managing long-term dividend payouts, capital expenditure undertakings and possible upswings in working capital requirements.

  This ratio is generally negative for most LDCs, but it is nonetheless a measure of free cash generated from operating funds (net income + depreciation + deferred taxes +/- other non-cash charges). A ratio that is consistently positive would suggest that the LDC generates surplus cash from its operations. This is rare for LDCs to accomplish on a consistent basis (which is why there are few companies rated Aa or Aaa).

5. *To assess financial strength and flexibility Moody's "smoothes" credit metrics by averaging them over a three-year time horizon whenever possible. The three years chosen are usually in the past, unless the projected years incorporate highly probable events driven by rate changes.*

Measurement metrics for this factor are as follows:

- **Interest Coverage: EBIT/interest**
  Weighting: 15%
- **Retained Cash Flow to Debt**
  Weighting: 15%
- **Debt to Capitalization (Excluding Goodwill)**
  Weighting: 15%
- **Free Cash Flow to Funds from Operations**
  Weighting: 15%

Factor Mapping: Financial Strength and Flexibility

	Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
EBIT/Interest		15%	> 7x	5 – 7x	3 – 5x	2 – 3x	1 – 2x	0 – 1x	< 0x
RCF/Debt		15%	> 26%	21 – 26%	15 – 21%	10 – 15%	5 – 10%	0 – 5%	< 0%
Debt / Book Capitalization (Excluding Goodwill)	60%	15%	< 30%	30 – 40%	40 – 50%	50 – 65%	65 – 85%	85 – 90%	> 90%
FCF/FFO		15%	> 10%	10% – (15%)	(15) – (30%)	(30%) – (45%)	(45%) – (60%)	(60%) – (75%)	< (75%)

Company Mapping Results: Financial Strength and Flexibility

Issuer Name	Current Senior Unsecured Rating	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/ Book Capitalization (Excluding Goodwill)	FCF/FFO	Indicated Rating: FCF/FFO
Alabama Gas Corporation	A1	3 – 5x	A	> 26%	Aaa	40 – 50%	A	(15%) – (30%)	A
New Jersey Natural Gas Company (Sec Aa3)	A1	> 7x	Aaa	10 – 15%	Baa	40 – 50%	A	> 10%	Aaa
Wisconsin Gas	A1	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	10% – (15)%	Aa
Boston Gas Company	A2	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(15%) – (30%)	A
Brooklyn Union Gas	A2	5 – 7x	Aa	10 – 15%	Baa	40 – 50%	A	(45%) – (60%)	Ba
KeySpan Gas East Corporation	A2	2 – 3x	Baa	21 – 26%	Aa	40 – 50%	A	10% – (15)%	Aa
Northern Illinois Gas	A2	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
North Shore Gas Company (Sec A1)	A2	3 – 5x	A	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Peoples Gas Light and Coke Compa (Sec A1)	A2	2 – 3x	Baa	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Public Service Co. of North Caro	A2	2 – 3x	Baa	15 – 21%	A	30 – 40%	Aa	(15%) – (30%)	A
Questar Gas Company	A2	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
Southern California Gas Company	A2	5 – 7x	Aa	21 – 26%	Aa	50 – 65%	Baa	(15%) – (30%)	A
Washington Gas Light Company	A2	5 – 7x	Aa	15 – 21%	A	30 – 40%	Aa	10% – (15)%	Aa
Terasen Gas Inc.	A3	1 – 2x	Ba	5 – 10%	Ba	65 – 85%	Ba	(15%) – (30%)	A
Colonial Gas Company (Sec A2)	A3	3 – 5x	A	15 – 21%	A	50 – 65%	Baa	10% – (15)%	Aa
Northwest Natural Gas Company	A3	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
Piedmont Natural Gas Company, In	A3	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Connecticut Natural Gas	A3	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A

Company Mapping Results: Financial Strength and Flexibility

Issuer Name	Current Senior Unsecured Rating	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/ Book Capitalization (Excluding Goodwill)	FCF/FFO	Indicated Rating: FCF/FFO
UGI Utilities, Inc.	A3	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	Aa
AGL Resources Inc.	Baa1	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(30%) – (45%)	Baa
Cascade Natural Gas Corp.	Baa1	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Indiana Gas Company, Inc.	Baa1	2 – 3x	Baa	5 – 10%	Ba	40 – 50%	A	(30%) – (45%)	Baa
Laclede Gas Company	Baa1	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
Southern Connecticut Gas (Sec A3))	Baa1	2 – 3x	Baa	15 – 21%	A	50 – 65%	Baa	(15%) – (30%)	A
Laclede Group, Inc. (The)	Baa2	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
South Jersey Gas Company	Baa2	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	Aa
Yankee Gas	Baa2	1 – 2x	Ba	10 – 15%	Baa	50 – 65%	Baa	< (75%)	Caa
Atmos Energy Corporation	Baa3	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Southwest Gas Corporation	Baa3	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(45%) – (60%)	Ba
SEMCO Energy, Inc.	Ba2	1 – 2x	Ba	5 – 10%	Ba	> 90%	Caa	(45%) – (60%)	Ba

Positive Outlier
Negative Outlier

Observations and Outliers

Interest Coverage

This ratio is generally compatible with LDCs' assigned credit ratings. Among the positive outliers in the "A" rated names is New Jersey Natural Gas, whose credit measures have proven much stronger than those for most of its peers. During the past few years earnings and cash flow improvements have resulted in higher interest charge coverage and lower leverage for the company. On the other end of the spectrum, Boston Gas Company shows higher interest expense to service relative to other similarly-rated high names.

In the "Baa" rated category we find that South Jersey Gas Company is rated lower than its interest coverage might suggest. This reflects the transitional nature of the company as it contemplates the issuance of additional debt in the future to help fund its capital expenditure requirements.

RCF/Debt

A positive outlier in the "A" rated category is Boston Gas, which has been able to produce strong cash flow under a performance-based rate (PBR) formula approved by regulators in Massachusetts. Negative outliers in the "Baa" category include Laclede Gas Company, where retained cash flow has been negatively affected by a policy of increasing dividend payouts.

Debt to Book Capitalization (Excluding Goodwill)

Low leverage generally correlates with high credit ratings, but there are a few exceptions. The "Ba" leverage factor score for Boston Gas Company and Colonial Gas Company, both subsidiaries of KeySpan, could be explained by the parent's use of push-down accounting. Under this approach, the LDCs were assigned a proportionate share of the cost of their acquisition debt and goodwill when KeySpan purchased them in 2000. The effect of pushing down a portion of the parent company's acquisition debt and goodwill raised financial leverage for these LDCs. This occurred not only because of the added debt burden from the parent but also because the allocated portions of goodwill resulted in a lower capital base (Moody's practice is to subtract the goodwill from equity for the regulated gas sector).

FCF/FFO

The scores for the free cash flow ratio are generally compatible with those of the assigned company ratings. A notable outlier in the "A" category includes Brooklyn Union Gas, which scored a "Ba" in this factor. During the past three years this company has had its cash flows stressed by a combination of high capital expenditures, high working capital uses and high dividend remittances to its parent. Outliers in the "Baa" rated names include South Jersey Gas, which is in transition, and Yankee Gas, which is in need of further rate relief and rate design improvements despite its recent rate filings, especially as it makes capital outlays in advance of rate recovery as in its current capital expenditures for construction of an LNG facility.

Final Considerations

To determine the overall rating, each of the eight assigned sub-factor ratings is converted into a numeric value based on the following scale:

1	3	6	9	12	15	18
Aaa	Aa	A	Baa	Ba	B	Caa

Each sub-factor's numeric point value is then multiplied by an assigned weight (as shown in Appendix A), summed.

Factor	Sub-Factor	Weighting
Sustainable Profitability	ROE	15%
	EBIT/Customer Base	5%
Regulatory Support	Regulatory Support & Relationship	10%
Ring Fencing	Ring-Fencing	10%
Financial Strength and Flexibility	EBIT/Interest	15%
	RCF/Debt	15%
	Debt/Capitalization (Ex. Goodwill)	15%
	FCF/FFO	15%
Total		**100%**

The total is then mapped to the table below, and an overall alpha-numeric rating is assigned based on where the score falls in the range.

Indicated Rating	Overall Score
Aaa	**= 1**
Aa	> 1 < 4.5
A	>= 4.5 < 7.5
Baa	>= 7.5 < 10.5
Ba	>= 10.5 < 13.5
B	>= 13.5 < 16.5
Caa	>= 16.5

Sample Calculation

	Rating	Rating Score	% of Total	Factor Score
Factor 1: Sustainable Profitability				
Sub-Factor 1	Aa	3	15%	0.5
Sub-Factor 2	Baa	9	5%	0.5
Factor 2: Regulatory Support				
Sub-Factor 3	Baa	9	10%	0.9
Factor 3: Ring Fencing				
Sub-Factor 4	Aaa	a	10%	0.1
Factor 4: Financial Strength and Flexibility				
Sub-Factor 5	A	6	15%	0.9
Sub-Factor 6	Aaa	1	15%	0.2
Sub-Factor 7	A	6	15%	0.9
Sub-Factor 8	A	6	15%	0.9
			100%	**4.8 = A1**

If an LDC'S sub-factors sum to a score of 4.8, as shown above, an overall rating of A1 would be assigned. On this scale, a lower score indicates a stronger credit profile than a higher score. If the LDC's sub-factors sum to a total score of 9.0, an overall rating of Baa would be assigned. The LDC would be considered to have an average Baa2 rating profile because it falls in the middle of that category range.

In this methodology we cover 30 gas utility companies. After placing these companies through the rating factor grid,

- 7 companies (23%) map to their assigned ratings
- 14 companies (47%; 70% cumulatively) fall within one notch of their existing ratings.
- 7 companies (23%; 93% cumulatively) have indicated ratings that are within two notches higher or lower than actual ratings
- All but two companies have actual ratings that fall within two notches of their ratings on the grid, with two companies' ratings — those of South Jersey Gas and Boston Gas — falling within three and four notches, respectively, outside of their factor summaries.[6]

South Jersey Gas currently has an assigned rating of Baa2, although the Moody's methodology suggests an A2 rating (reflecting, primarily, that recent past performance may differ from future results). When one factors the company's recent rate case capitalization assumptions with the appropriate adjustments made by Moody's, leverage rises, retained cash flows decline (on account of higher dividend payouts) and coverage ratios are reduced. The company remains solidly in the investment grade category. However, the financial metrics for this company are currently in transition as implied by the methodology and the ratings based on recent historical data may not be applicable for the future.

Boston Gas is rated A2 senior unsecured compared to the model rating of Baa3. This reflects the results of push-down accounting relating to KeySpan's acquisition of Eastern Enterprises, whereby a portion of the acquisition debt and goodwill issued by the parent was allocated to Boston Gas. Additionally, as KeySpan is currently under review for possible downgrade, following the announcement that it is being acquired by National Grid Plc, a UK gas and electricity transmission business, in a transaction valued at $7.3 Billion (£4.2 Billion). The transaction may put pressure on the regulated subsidiary to support the additional debt.

While there may be outliers from time to time under the gas LDC rating methodology, the vast majority of the companies rated by Moody's do fall within the two rating notches targeted by this methodology, and their credit ratings could be explained by the relevant factors. At any given time, we could assume that one or more issuers are in a state of transition and may therefore find themselves positioned as outliers relative to their assigned ratings when compared against the ratings implied under the gas LDC methodology (i.e. the deviations are either higher or lower by more than the two desirable notches).

6. *See Appendix C for Summary Chart on Moody's Public Rating versus Indicated Model Rating.*

Related Research

Special Comments:

Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings, June 2006 (98022)

Update On The Gas Supply and Liquidity Needs of Gas LDCs Post Hurricane Katrina, September 2005 (94440)

Impact Of Conservation On Gas Margins And Financial Stability In The Gas LDC Sector, June 2005 (92787)

Comparative ROE Attributes of US Local Gas Distribution Companies, July 2004 (87301)

Gas Utility Cash Management Practices Reflect the Diversity of their Credit Ratings, October 2003 (79828)

Negative Rating Trend For Local Gas Distribution Companies: Impact Of Diversification And Warm Weather, October 2002 (76344)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Appendix A

CONSOLIDATED GAS UTILITY RATING GRID

		Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
Sustainable Profitability	Return on Equity		15.0%	> 19%	14 – 19%	9 – 14%	5 – 9%	2 – 5%	0 – 2%	< 0%
	Ebit / # of Residential & Commercial Customers	20%	5.0%	> $350	$250 – $350	$150 – $250	$100 – $150	$50 – $100	$0 – $50	< $0
Regulatory Support	Regulatory Support and Relationship	10.0%	10.0%	*Exceptional Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission always willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Utility Commission grants all rate design features to allow LDC to recover costs on a complete and timely basis.	*Very Good Proactive Support* by Utility Commission to allow LDCs to timely adjust rates to cover all costs of service; Utility commission highly willing to help LDC establish a cooperative framework for discussions, hearings and implementation of better rate design to help LDCs' shareholders and consumers alike. Rate design is near "bulletproof" cover for LDC risks. Requested rate increases tend to be approved in less than 9 months.	*Good Support* by Utility Commission to allow LDCs to amend rate designs. Company gets good support in proposing new solutions to deal with common utility problems such as conservation and weather variables; Differences between LDCs and utility commission are likely to be resolved. Rate filings tend to be approved under 12 months.	*Reasonable support* from Utility Commission to allow LDCs to recoup allowed expenses; Company gets some support in proposing new solutions to deal with common utility problems such as conservation and weather issues; Differences between LDCs and Utility Commission are reasonably resolved in a timely manner and rate cases tend to be approved in 12 – 15 months with at least 50% of LDC's target requests being granted.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner and/or staff tends to play the role of "consumer advocate" that often counters proposals or initiatives advanced by the LDC. Cases often take over 15 months to resolve or LDC is frozen out of rate filings for over 18 months.	*Inadequate support* from Utility Commission to allow LDCs to recoup allowed expenses; Utility commissioner often plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC; Company is seldom involved with working on special task forces to deal with issues of rising account delinquencies or educating customers on conservation or warm weather issues. Utility suffers from increasing regulatory lag and lacks rate relief necessary to earn allowed ROE.	*Inadequate and weak support* from Utility Commission to allow LDCs to recoup allowed expenses. Utility commissioner always plays the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC; Company is hardly ever involved with working on special task forces to deal with issues of rising concern to utility or customers. Unsupportive commission/state legislature or consumer base. Utility can't earn allowed ROE.

		Weighting Ranges	Individual Weighting	Aaa	Aa	A	Baa	Ba	B	Caa
Ring-Fencing	Ring-Fencing Quality (regulated or self-imposed)	10.0%	10.0%	*Excellent* ring-fencing provisions isolating Utility from Non-Utility; No commingling of funds; Utility cash accounts are separated from rest of company; Inter-company loans never permitted between utility and non-utility; No portion of Utility dividend payment to parent ever ends up being allocated to non-utility. Strong	*Very Good* ring-fencing provisions; Utility and Non-Utility highly unlikely to commingle funds; Separate cash program or own utility money pool; Inter-company loans not permitted between utility and non-utility; Utility dividend payment to parent never end up being allocated to non-utility.	*Good* ring-fencing provisions; Utility and Non-Utility are unlikely to commingle funds; Separate utility money pool or utility accounts; Inter-company loans not permitted between utility and non-utility; Utility dividend payment to parent unlikely to be allocated to non-utility.	*Reasonable* ring-fencing provisions; Utility and Non-Utility may need to commingle funds via consolidated corporate money pool; Bond indentures or bank credit agreements may reasonably restrict the utility from financial dealings with non utility; Inter-Company loans between utility and non-utility rare.	*Inadequate* ring-fencing provisions; Utility often participates in corporate cash money pool that includes non-utility and funds are often commingled; Regulators usually do not have a requirement that LDCs remain investment grade. Bond indentures or bank credit agreements may not restrict the utility financial dealings with non- utility.	*Inadequate* ring-fencing provisions; Utility often participates in corporate cash money pool that includes non-utility and funds are generally commingled; No requirement for LDCs to remain investment grade. Bond indentures or bank credit agreements usually do not restrict the utility financial dealings with non- utility. Inter-company loans between utility and non-utility common place.	*Inadequate and weak* ring-fencing provisions; Utility and Non-Utility generally always commingle funds; No requirement for LDCs to remain investment grade; Bonds indentures/ bank agreements never restrict utility financial dealing with non-utility. Inter-company loans between utility and non-utility are common place; Utility dividends to parent may fund non-utility needs.
				Corporate Governance protecting utility interests which are treated as core operation.	Very Good Corporate Governance. May lack formal regulatory or creditor leverage restrictions or IG requirement for utility, but company has strong policy of ring-fencing utility.	Good Corporate Governance of utility	Satisfactory Corporate Governance. Gas utility contributes less than 90% of consolidated group EBIT and may not be primary growth engine.	Inadequate Corporate Governance protection for utility as stand-alone entity.	Inadequate Corporate Governance for utility as a stand alone entity.	Inadequate and weak Corporate Governance of utility interests.
Financial Strength & Flexibility	EBIT/Interest		15.0%	> 7x	5 – 7x	3 – 5x	2 – 3x	1 – 2x	0 – 1x	< 0x
	RCF/Dcbt		15.0%	> 26%	21 – 26%	15 – 21%	10 – 15%	5 – 10%	0 – 5%	< 0%
	Debt / Book Capitalization (Excluding Goodwill)	60.0%	15.0%	< 30%	30 – 40%	40 – 50%	50 – 65%	65 – 85%	85 – 90%	> 90%
	FCF/FFO		15.0%	> 10%	10% – (15%)	(15) – (30%)	(30%) – (45%)	(45%) – (60%)	(60%) – (75%)	< (75%)

Appendix B

CONSOLIDATED FACTOR MAPPING RESULTS

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio	Indicated Rating: Regulatory Support	Indicated Rating: Ring Fencing	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/ Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/Book Capitalization (Excluding Goodwill)	FCF/ FFO	Indicated Rating: FCF/FFO
Alabama Gas Corporation	A1	14 – 19%	Aa	$150 – $250	A	Aaa	Baa	3 – 5x	A	> 26%	Aaa	40 – 50%	A	(15%) – (30%)	A
New Jersey Natural Gas Company (Sec Aa3)	A1	9 – 14%	A	$150 – $250	A	Aaa	Aaa	> 7x	Aaa	10 – 15%	Baa	40 – 50%	A	> 10%	Aaa
Wisconsin Gas	A1	5 – 9%	Baa	$100 – $150	Baa	Baa	Baa	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	10% – (15)%	Aa
Boston Gas Company	A2	2 – 5 %	Ba	$150 – $250	A	Baa	Baa	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(15%) – (30%)	A
Brooklyn Union Gas	A2	9 – 14%	A	$150 – $250	A	Baa	Aaa	5 – 7x	Aa	10 – 15%	Baa	40 – 50%	A	(45%) – (60%)	Ba
KeySpan Gas East Corporation	A2	9 – 14%	A	$250 – $350	Aa	Baa	Aaa	2 – 3x	Baa	21 – 26%	Aa	40 – 50%	A	10% – (15)%	Aa
Northern Illinois Gas	A2	5 – 9%	Baa	$50 – $100	Ba	Baa	Baa	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
North Shore Gas Company (Sec A1)	A2	5 – 9%	Baa	$50 – $100	Ba	Ba	Baa	3 – 5x	A	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Peoples Gas Light and Coke Compa (Sec A1)	A2	5 – 9%	Baa	$100 – $150	Baa	Ba	Baa	2 – 3x	Baa	5 – 10%	Ba	30 – 40%	Aa	(15%) – (30%)	A
Public Service Co. of North Caro	A2	5 – 9%	Baa	$150 – $250	A	Aaa	Aaa	2 – 3x	Baa	15 – 21%	A	30 – 40%	Aa	(15%) – (30%)	A
Questar Gas Company	A2	9 – 14%	A	$50 – $100	Ba	Ba	A	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
Southern California Gas Company	A2	14 – 19%	Aa	$50 – $100	Ba	A	Aaa	5 – 7x	Aa	21 – 26%	Aa	50 – 65%	Baa	(15%) – (30%)	A
Washington Gas Light Company	A2	9 – 14%	A	$150 – $250	A	Baa	Aaa	5 – 7x	Aa	15 – 21%	A	30 – 40%	Aa	10% – (15)%	Aa
Terasen Gas Inc.	A3	9 – 14%	A	>$350	Aaa	Aa	Aa	1 – 2x	Ba	5 – 10%	Ba	65 – 85%	Ba	(15%) – (30%)	A
Colonial Gas Company (Sec A2)	A3	2 – 5 %	Ba	$250 – $350	Aa	Baa	Baa	3 – 5x	A	15 – 21%	A	50 – 65%	Baa	10% – (15)%	Aa
Northwest Natural Gas Company	A3	9 – 14%	A	$150 – $250	A	Aaa	Baa	3 – 5x	A	10 – 15%	Baa	40 – 50%	A	(30%) – (45%)	Baa
Piedmont Natural Gas Company, In	A3	9 – 14%	A	$150 – $250	A	Aaa	Aaa	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Connecticut Natural Gas	A3	2 – 5 %	Ba	$250 – $350	Aa	Ba	Baa	3 – 5x	A	15 – 21%	A	40 – 50%	A	(15%) – (30%)	A
UGI Utilities, Inc.	A3	14 – 19%	Aa	$250 – $350	Aa	Baa	A	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	Aa
AGL Resources Inc.	Baa1	14 – 19%	Aa	$150 – $250	A	Baa	Baa	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	(30%) – (45%)	Baa
Cascade Natural Gas Corp.	Baa1	9 – 14%	A	$100 – $150	Baa	Baa	Aaa	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Indiana Gas Company, Inc.	Baa1	5 – 9%	Baa	$100 – $150	Baa	Aa	Baa	2 – 3x	Baa	5 – 10%	Ba	40 – 50%	A	(30%) – (45%)	Baa

Issuer Name	Current Senior Unsecured Rating	ROE	Indicated Rating: ROE	EBIT/# of Residential & Commercial Customers	Indicated Rating: Operating Ratio	Indicated Rating: Regulatory Support	Indicated Rating: Ring Fencing	EBIT / Interest Expense	Indicated Rating: EBIT/ Interest Expense	RCF / Debt	Indicated Rating: RCF/ Debt	Debt / Book Capitalization (Excluding Goodwill)	Indicated Rating: Debt/Book Capitalization (Excluding Goodwill)	FCF/ FFO	Indicated Rating: FCF/FFO
Laclede Gas Company	Baa1	9 – 14%	A	$100 – $150	Baa	Aa	A	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
Southern Connecticut Gas (Sec A3))	Baa1	2 – 5 %	Ba	$150 – $250	A	Baa	Baa	2 – 3x	Baa	15 – 21%	A	50 – 65%	Baa	(15%) – (30%)	A
Laclede Group, Inc. (The)	Baa2	9 – 14%	A	$100 – $150	Baa	Aa	Baa	2 – 3x	Baa	5 – 10%	Ba	50 – 65%	Baa	(15%) – (30%)	A
South Jersey Gas Company	Baa2	9 – 14%	A	$150 – $250	A	Aa	Aaa	3 – 5x	A	10 – 15%	Baa	50 – 65%	Baa	10% – (15)%	Aa
Yankee Gas	Baa2	2 – 5 %	Ba	$150 – $250	A	Ba	Baa	1 – 2x	Ba	10 – 15%	Baa	50 – 65%	Baa	< (75%)	Caa
Atmos Energy Corporation	Baa3	9 – 14%	A	$50 – $100	Ba	Baa	Baa	2 – 3x	Baa	10 – 15%	Baa	50 – 65%	Baa	(15%) – (30%)	A
Southwest Gas Corporation	Baa3	5 – 9%	Baa	$50 – $100	Ba	Ba	Aaa	1 – 2x	Ba	10 – 15%	Baa	65 – 85%	Ba	(45%) – (60%)	Ba
SEMCO Energy, Inc.	Ba2	<0%	Caa	$100 – $150	Baa	Ba	Baa	1 – 2x	Ba	5 – 10%	Ba	> 90%	Caa	(45%) – (60%)	Ba

Positive Outlier
Negative Outlier

Appendix C

MOODY'S PUBLIC RATING VS. INDICATED MODEL RATING

Summary of LDCs Notch Difference

		0 Notch Difference	7
ACCURACY:		1 Notch Difference	14
# of Companies in Methodology Study	30	2 Notch Difference	7
# of Companies within Notching Range	28	Outliers	2
% Companies within Notching Range	**93%**	**Total Companies**	**30**

Companies	Public Ratings	Model Ratings	Notch Difference
Alabama Gas	A1	A1	0
New Jersey Natural Gas	A1	Aa3	-1
Wisconsin Gas LLC	A1	A3	2
Boston Gas Company	A2	Baa3	4
Brooklyn Union Gas	A2	A3	1
KeySpan Gas East	A2	A1	-1
Northern Illinois Gas	A2	Baa1	2
NorthShore Gas	A2	Baa1	2
People Gas Light	A2	Baa1	2
Public Service Co of NC	A2	A1	-1
Questar Gas	A2	A3	1
Southern California Gas	A2	A1	-1
Washington Gas Light	A2	Aa3	-2
Colonial Gas	A3	A3	0
Northwest Natural Gas	A3	A3	0
Piedmont Natural Gas	A3	A2	-1
Connecticut Natural Gas	A3	Baa1	1
Terasen Gas Inc.	A3	Baa1	1
UGI Utilities Inc.	A3	A2	-1
AGL Resources Inc.	Baa1	A3	-1
Cascade Natural Gas	Baa1	A3	-1
Indiana Gas Company	Baa1	Baa1	0
Laclede Gas Company	Baa1	Baa1	0
Southern Connecticut Gas	Baa1	Baa1	0
Laclede group Inc	Baa2	Baa1	-1
South Jersey Gas	Baa2	A2	-3
Yankee Gas	Baa2	Ba1	2
Atmos Energy	Baa3	Baa1	-2
Southwest Gas Corp	Baa3	Baa3	0
SEMCO Energy Inc.	Ba2	Ba3	1

Positive Outlier
Negative Outlier

Appendix D

SUMMARY OF NON-FINANCIAL LDC SUB-FACTORS

1. **Regulatory Support & Relationship:** While factor No. 1 measures the adequacy and effectiveness of the LDC's business model, this factor measures both the ***ability*** and ***willingness*** of the utility regulatory commission to grant the necessary support and protection that the LDC requests in its business plans. The utility commission must be willing to help the LDC establish a cooperative framework for discussions, hearings and staff relations with its indigenous utilities as well as have the state constitutional powers to put the necessary regulations or rate designs in place. While the LDC is interested in obtaining flexibility in regulatory growth and risk protection, the commission is usually focused on ensuring a stable utility operation with reliable customer service under reasonable prices. Questions to consider include
   a. Does the Company have good working relationship with the state regulators to recoup allowed expenses and the necessary trust of its regulators that it is doing the right thing for its customers and shareholders alike?
   b. Does the Company maintain an active dialogue with the commissioners and staff in discussing and proposing new solutions to common utility problems and working on special task forces to deal with common industry issues of rising account delinquencies as gas shortages rise and prices increase, or in educating customers as to gas conservation or safety?
   c. What is the role of the commission staff, to serve as a technical advisor to the utility commission in facilitating constructive discussions with the company or does it play the role of "consumer advocate" that tends to counter proposals or initiatives advanced by the LDC in an adversarial atmosphere for dispute resolutions.
   d. How are differences between the LDC and its utility commission typically resolved, do they have a "settlement" approach where various interveners and interested parties are brought together for amicable solutions or do they resort to court actions and counter-actions to achieve their ends?
5. **Ring Fencing Quality:** We find that either regulators or creditors or the companies themselves impose certain ring-fencing parameters on the financial operations of the LDCs. Generally, ring-fencing is a desirable attribute as the utility is assured a certain financial insulation from the non-utility operations of the parent company and is not susceptible to supporting the business of its non-utility affiliates. The greater the degree of ring-fencing, the more separated is the utility from its non-utility affiliates. The strongest ring-fencing requirements tend to come from legislative statutes and regulators, followed by bond indentures and bank creditors. Occasionally, LDCs have self-imposed guidelines that could be just as rigid as those regulated, but this would depend on the analysts' confidence in the utility's strict adherence to its own firewall policies and practices. A utility's self-imposed restrictions on its own operations and its attempts at insulating itself from other non-regulated affiliates could also be evident in its corporate governance policies and practices. Issues to consider include
   a. Are inter-company loans or advances permitted between utility and non-utility operations of the same corporate family?
   b. Does the utility participate in a corporate cash money pool that includes non-utility subsidiaries, such that it is possible for the utility to deposit its surplus funds in general corporate money pool which ends being used by the non-utility affiliates for their WC needs?
   c. Does the utility dividend payment to its parent (perhaps in excess of what the parent needs to pay public shareholders) have a portion that ends up being allocated to non-utility affiliates for their operating or investment needs?
   d. Do the regulators stipulate maximum leverage ratios for the LDC or have a requirement that the LDC remain investment-grade in order to preserve its service franchise?
   e. What is the quality of the LDC's corporate governance?

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Author	Editor	Associate Analyst	Senior Associate	Production Specialist
Edward Tan	*Dale Wagner*	*Sharon Roberts*	*Jacquelyn Ward*	*Yung Louie*