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June 30, 2011

Via Email
Original via Courier

Ms. Alanna Gillis
Acting Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

Re: FortisBC Inc. Application for Approval of 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan

FortisBC Inc. (FortisBC or the Company) attaches its 2012 – 2013 Revenue Requirements and 2012 Integrated System Plan (collectively, the Application). This Application is comprised of two parts. Each part is, in turn, comprised of different components:

Part I – 2012 – 2013 Revenue Requirements (2012-13 RRA)

a) 2012 – 2013 Revenue Requirements

b) 2012 – 2013 Capital Expenditure Plan

Part II – 2012 Integrated System Plan

Volume 1: a) Introduction

b) 2012 Long Term Capital Plan

Volume 2: c) 2012 Long Term Resource Plan

d) 2012 Long Term Demand Side Management Plan

2012 – 2013 Revenue Requirements Application

The Company's 2012 – 2013 Revenue Requirements, following a Performance-Based Regulation (PBR) Plan in effect from 2007 through 2011, is a fully-developed cost of service revenue requirement. FortisBC is seeking approval of general rate increases of 4.0 percent effective January 1, 2102 and 6.9 percent effective January 1, 2013. Interim rates effective January 1, 2012 may be necessary, depending on the regulatory timetable established for review of the Application.

The major contributors to the forecast revenue deficiencies in 2012 and 2013 are increased Power Purchase Expense and increased costs of financing the Company's growing rate base, which is necessary to continue providing safe, reliable and cost-effective service to its more than 161,000 direct and indirect customers. Operations and Maintenance Expense increases by an average of 1.75 percent annually over the test period.

Tab 6 of the 2012-13 RRA includes FortisBC's 2012 – 2013 Capital Expenditure Plan (2012-13 Capital Plan), which outlines capital projects and Demand Side Management expenditures totaling $105.9 million in 2012 and $129.1 million in 2013, inclusive of projects previously approved, or for which the Company intends to file an application for a Certificate of Public Convenience and Necessity. The Company requests approval for capital expenditures on projects in the amounts of $87.4 million and $86.9 million in 2012 and 2013, respectively.

2012 Integrated System Plan

In its 2012 Integrated System Plan (2012 ISP), FortisBC outlines its long-term strategic direction in the areas of capital and resource planning and energy conservation. The 2012 ISP provides the long-term context for the 2012-13 RRA and 2012-13 Capital Plan.

The Company is seeking a determination that the 2012 ISP is in the public interest.

Proposed Regulatory Process

FortisBC has proposed a Negotiated Settlement Process, or in the alternative, a written public hearing process, for the review of this Application. The Company is fully prepared to proceed with an oral public hearing, as contemplated by the Negotiated Settlement Agreement (NSA) concerning the 2007 – 2009 PBR Plan extension, if that is the wish of the Commission and Interveners. A Procedural Conference is proposed following the Information Request component of the Application, to determine the remainder of the regulatory process.

The Company proposes that the Load Forecast be reviewed by a joint Load Forecast Technical Committee, to be composed of interested Registered Interveners, with the full participation of the Commission staff, as agreed to in the NSA concerning FortisBC's 2011 Revenue Requirements Application. It is proposed that the Load Forecast be excluded from the Information Requests, and that a report detailing the committee's discussions and recommendations be submitted as evidence in the proceeding.

FortisBC will hold a Workshop on the Application on Friday, July 22, 2011, at the Holiday Inn Express, 2429 N. Highway 97, Kelowna, BC, commencing at 9:00 a.m.

Request for Confidentiality

FortisBC is requesting confidentiality for one component of the Application. In the 2012-13 RRA, Table 4.3.2.1 Labour Inflation, contains information which, if disclosed publicly, could compromise future negotiations between the Company and its unionized labour bargaining units. Therefore Table 4.3.2.1 of the 2012-13 RRA has been redacted and the complete table is being filed with the Commission under separate cover.

If further information is required, please contact the undersigned at (250) 717- 0890.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

2012 – 2013 Revenue Requirements
(2012-13 RRA)

Tab 1
Executive Summary

June 30, 2011

FortisBC Inc.

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1.0 SUMMARY OF REVENUE REQUIREMENTS FOR 2012 AND 2013

In 2006, FortisBC Inc. (FortisBC or the Company) negotiated a settlement agreement (the 2006 NSA) that included a form of Performance Based Regulation (PBR) for setting rates in 2007 and 2008 with an option to extend the agreement for 2009 upon agreement by the Parties. The 2006 NSA was approved by the British Columbia Utilities Commission (the Commission) by Order No. G-58-06.

In 2008, the Company and its stakeholders negotiated an extension of the PBR Plan for a term ending December 31, 2011. The Negotiated Settlement Agreement (NSA) concerning FortisBC's 2009 Revenue Requirements and the extension of the PBR Plan was approved by Commission Order G-193-08.

The Company strongly believes that the PBR Plan has been beneficial to FortisBC customers. Performance metrics have generally been maintained or improved, while encouraging the Company to operate as effectively and efficiently as possible. As an example, as discussed in Section 1.7 and in greater detail in Section 4.3 of this Application, the Company's Base O&M per Customer have remained relatively consistent on a nominal basis from 2007 through 2013 and have declined on an inflation adjusted basis.

The 2011 Revenue Requirements Application (RRA) stated that 2011 would be the final such application to be submitted under the then current PBR Plan. Therefore, the 2012-13 RRA is based on a fully developed Cost of Service revenue requirement.

FortisBC, as a regulated public utility operating in the Province of British Columbia, has a mandate to provide safe, reliable service to its customers. It must fulfill this requirement against a backdrop of provincial policy and legislation such as the *2007 BC Energy Plan* (the Energy Plan), *Utilities Commission Act*, R.S.B.C. 1996, c.473 (the Act) and the *Clean Energy Act, S.B.C. 2010.C.22*, that was enacted in 2010. In addition, under Cost of Service regulation the Company must make every reasonable effort to ensure that rates reflect prudently incurred costs and are the result of sound decision making and good utility practice.

Based on financial and operating results to April 30, 2011 the Company forecasts that the revenue required to provide service to its customers in 2012 is $294.5 million and $319.1 million in 2013 which results in a general rate increase of 4.0 percent and 6.9 percent in each respective year.

2011 Interim Rates

FortisBC retail rates as the date of this Application include an interim increase, approved by Commission Order G-91-11, reflecting the impact on the Company's 2011 Power Purchase Expense resulting from BC Hydro's interim rate increase effective April 1, 2011. At this time, no final decision has been rendered by the Commission on BC Hydro's F2012 to F2014 Revenue Requirements Application (the BC Hydro Application), With respect to FortisBC's 2011 interim rates, the Company requests that the Commission approve as firm its existing, interim, rates. The Company further requests approval to implement any changes arising from a final decision in the BC Hydro Application (the BC Hydro Decision) which effect the 2011 Power Purchase Expense in the following manner.

If the BC Hydro Decision is issued prior to the determination of FortisBC's 2012 permanent rate increase, any change in 2011 Power Purchase Expense will be incorporated into the FortisBC firm rates for 2012.

If the BC Hydro Decision is issued after the determination of FortisBC's 2012 permanent rate increase, any change in 2011 Power Purchase Expense resulting from the difference between BC Hydro's F2012 interim and F2012 final rates will be recorded in the proposed Power Purchase Variance Deferral Account which is described in Section 4.2 of the Application, to be amortized into customer rates in 2014.

1.1 STRUCTURE OF THE APPLICATION

Because the 2012-13 RRA is based on a fully developed Cost of Service revenue requirement, its layout is slightly different than the Company's recent applications. This Executive Summary is followed by tabs dealing with each major input to the Revenue Requirements as follows:

- Tab 2 Accounting Policy – a discussion of the various changes to Canadian Generally Accepted Accounting Principles (CGAAP);
- Tab 3 Load and Customer Forecast – detailed load and customer count by rate class;
- Tab 4 Cost of Service – a detailed of the Company's Cost Of Service;
- Tab 5 Rate Base – a summary of the Company's forecast 2012 and 2013 rate base;
- Tab 6 2012 and 2013 Capital Expenditure Plan (2012-13 Capital Plan);
- Tab 7 Financial Schedules; and

- Tab 8 Approvals and Process.

1.2 RATE DRIVERS

In this Application, FortisBC has applied to the Commission for an interim refundable rate increase of 4.0 percent, effective January 1, 2012, and 6.0 percent effective January 1, 2013 reflecting total revenue requirements of $294.5 million in 2012 and $319.1 million in 2012 and 2013 respectively.

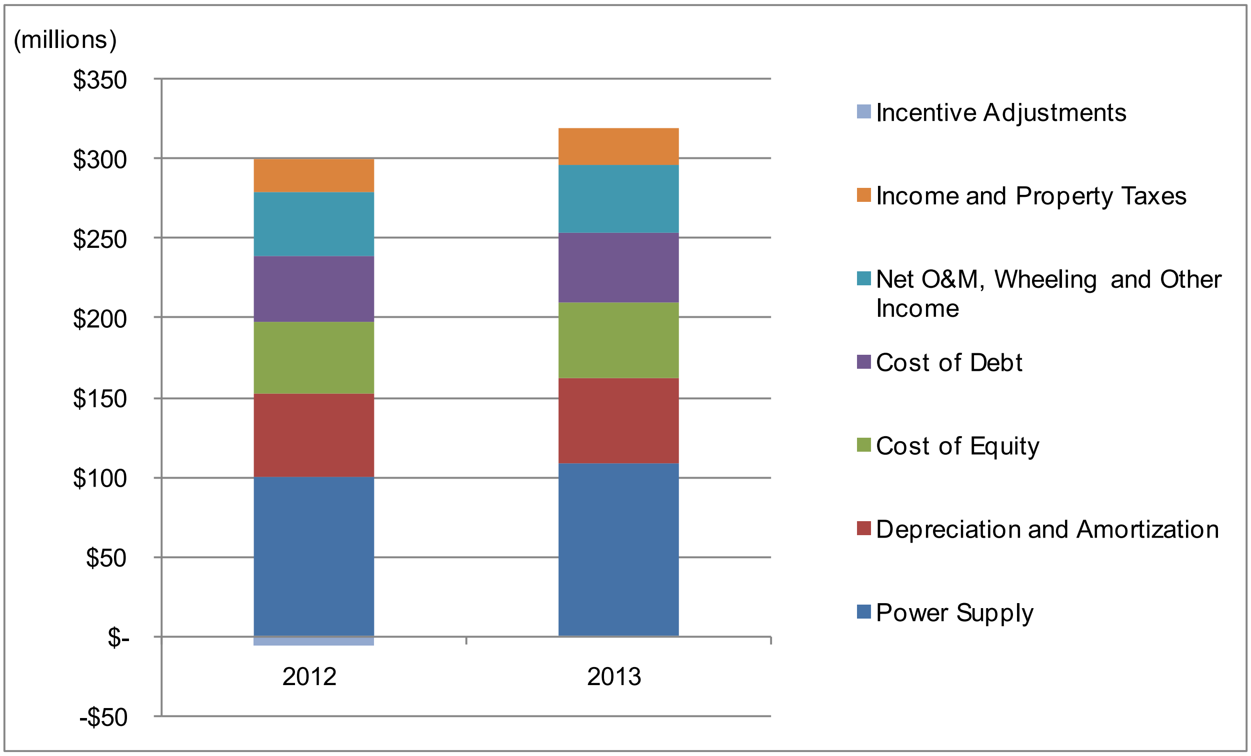
An Overview of 2012 and 2013 Revenue Requirements is presented in Table 1.2 below.

Table 1.2 - Revenue Requirements Overview

		Actual 2010	Forecast 2011	Approved 2011	Increase (Decrease)	Forecast 2012	Increase (Decrease)	Forecast 2013
					($000s)			
1	Sales Volume (GWh)	3,046	3,187	3,162	31	3,193	39	3,233
2	Rate Base	945,637	1,071,197	1,093,241	52,012	1,145,253	66,928	1,212,181
3	Return on Rate Base	7.77%	7.96%	7.67%	-0.10%	7.57%	-0.01%	7.55%
4								
5	**REVENUE DEFICIENCY**							
6								
7	**POWER SUPPLY**							
8	Power Purchases	71,964	75,956	81,212	9,772	90,984	7,837	98,821
9	Water Fees	9,256	8,977	9,381	300	9,681	172	9,853
10		81,220	84,933	90,593	10,072	100,665	8,009	108,674
11	**OPERATING**							
12	O&M Expense	46,148	53,885	53,885	287	54,172	1,622	55,794
13	Capitalized Overhead	(9,529)	(10,777)	(10,777)	(57)	(10,834)	(324)	(11,159)
14	Wheeling	4,050	4,243	3,338	1,387	4,725	508	5,233
15	Other Income	(6,452)	(7,402)	(5,455)	(2,026)	(7,481)	316	(7,165)
16		34,217	39,949	40,991	(409)	40,582	2,122	42,704
17	**TAXES**							
18	Property Taxes	12,238	13,917	13,940	592	14,532	553	15,085
19	Income Taxes	4,544	9,440	6,733	(681)	6,052	1,811	7,862
20		16,782	23,357	20,673	(89)	20,584	2,364	22,947
21	**FINANCING**							
22	Cost of Debt	35,138	39,364	40,505	814	41,319	2,234	43,553
23	Cost of Equity	38,293	45,922	43,292	2,060	45,352	2,650	48,002
24	Depreciation and Amortization	41,771	45,350	45,498	5,900	51,399	1,829	53,228
25		115,201	130,636	129,296	8,774	138,070	6,714	144,784
26								
27	Prior Year Incentive True Up	(2,690)	(2,770)	(1,089)	709	(380)	380	-
28	Flow Through Adjustments	2,385	2,406	(2,129)	(276)	(2,406)	2,406	-
29	ROE Sharing Incentives	(325)	2,630	448	(3,079)	(2,630)	2,630	-
30		(630)	2,266	(2,770)	(2,646)	(5,416)	5,416	-
31								
32	**TOTAL REVENUE REQUIREMENT**	**246,791**	**281,141**	**278,783**	**15,701**	**294,484**	**24,625**	**319,109**
33								
34	ADJUSTED REVENUE REQUIREMENT					294,484		319,109
35	**LESS: REVENUE AT APPROVED RATES**					283,289		298,618
36	**REVENUE DEFICIENCY for Rate Setting**					**11,195**		**20,490**
37								
38	**RATE INCREASE 2012-13**					**4.00%**		**6.90%**

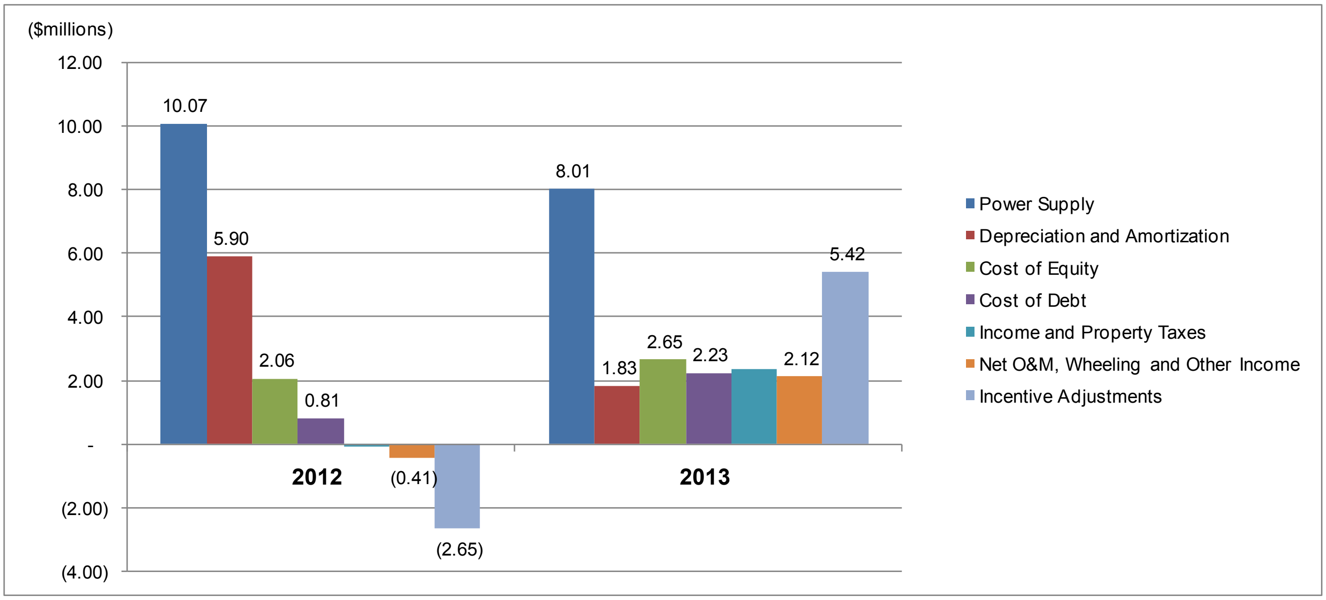
The components of Revenue Requirements for each year are presented below. On average, Power Supply costs comprise 34 percent of the 2012 and 2013 revenue requirements. Financing costs including Cost of Debt, Cost of Equity, and Depreciation and Amortization represent approximately 46 percent of the 2012 and 2013 Revenue Requirements, with operating costs and taxes responsible for the remaining 20 percent.

Figure 1.2-1 - Average Composition of the 2012 and 2013 Revenue Requirement



A graphic representation of the components of the revenue deficiency is presented below.

Figure 1.2-2 - 2012 and 2013 Revenue Deficiency Components



1.3 REVENUE AT EXISTING RATES

For the purposes of calculating revenue deficiency, Revenue at Existing Rates is determined by applying the currently approved rates (as at June 1, 2011) to the forecast billing determinants (customer count, energy and demand) for each customer class. The Load and Customer Forecast is described in detail in Tab 3 of this Application.

Table 1.3-1 below shows the changes in energy sales by customer group for 2012 and 2013.

Table 1.3-1 - Increased Energy Sales for 2012 and 2013

(GWh)	2012	2013
Residential	9	13
General Service	11	13
Wholesale	8	10
Industrial	7	5
Lighting	-1	-1
Irrigation	0	0
Net Load	34	39
Increase over previous year	1.1%	1.2%

Table 1.3-2 below summarizes the actual revenues for 2010, projected revenues for 2011, and forecast revenue at June 1, 2011 rates for 2012 and 2013.

Table 1.3-2 - Actual and Projected Revenues (2010-2013)

	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
	($000s)			
Residential	114,375	133,108	137,502	142,235
General Service	59,957	64,425	60,245	57,510
Industrial	16,093	17,968	18,090	18,419
Wholesale	51,765	59,936	62,114	63,864
Lighting and Irrigation	4,602	5,704	5,338	5,239
Total	**246,791**	**281,141**	**283,289**	**287,266**

1.4 REVENUE REQUIREMENT COMPONENTS

While the general rate increases are due to a number of factors they are primarily a result of:

a) a growing rate base;

b) an increase in the cost of financing of that rate base;

c) increased power purchase costs; and

d) taxes.

1.5 RATE BASE

Details of FortisBC's actual and forecast Rate Base for 2010 through 2013 are found in Tab 5 to this Application.

Table 1.5 summarizes FortisBC's Net Additions to Plant in Service and Rate Base from 2010 through 2013 forecast. Capital expenditures, which are primarily related to improving service reliability and meeting increased customer energy demands, are the cause of the growth in FortisBC's Rate Base.

Table 1.5 - Capital Expenditures and Utility Rate Base 2010 to 2013

		2010	2011F	2012F	2013F
		($ millions)			
1	**Net Additions to Plant**	130.1	129.7	86.0	125.9
2	**Rate Base (Mid-Year)**	945.6	1,071.2	1,145.3	1,212.2

Net Additions to Plant are nearly equivalent in 2010 and 2011 but declines in 2012, as several, large multi year projects such as the Okanagan Transmission Reinforcement and Corra Linn Upgrade Life Extension Projects near completion in 2011. The 2013 Net

Additions to Plant are forecast to increase to near pre-2012 levels due to the completion of several major transmission and general plant projects including the Grand Forks Transformer Addition, Kootenay Long Term Facility Strategy, Trail Buildings Purchase and Advanced Metering Infrastructure projects.

Details of proposed capital expenditures for the 2012 and 2013 test years are located in the 2012 – 2103 Capital Expenditure Plan in Tab 6.

1.6 POWER SUPPLY

Power Supply includes Power Purchase and Water Fee costs. Power Purchases are forecast to be $91.0 million in 2012 and $98.8 million in 2013. This is compared to $76.0 million currently estimated for 2011. The increases in 2012 and 2013 are primarily due to an increase in forecast load, greater use of the BC Hydro Power Purchase Agreement, annual increases to the Brilliant and BC Hydro rates, and the inclusion of management costs associated with resource planning and power purchase activities. The details of 2012 and 2013 Power Purchase Expense are discussed in Section 4.1 of this Application.

Table 1.6 - Power Purchase Expense

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
			(GWh)		
1	FortisBC	1,530	1,604	1,600	1,604
2	DSM	-	15	53	89
3	Power Purchases (net of surplus sales)	1,796	1,898	1,902	1,939
4	Total System Load (before DSM savings)	3,326	3,517	3,555	3,632
5	Less DSM	-	(15)	(53)	(89)
6	Total System Load (including DSM savings)	3,326	3,502	3,502	3,543
			($000s)		
7	Expense – Energy	60,591	61,466	73,657	79,381
8	Expense – Capacity	12,386	14,330	17,307	18,879
9	Capital Projects, Accounting & Other Adjustments	(1,013)	160	(1,191)	(706)
10	Management Expense	0	0	1,211	1,266
11	Total Power Purchase Expense	71,964	75,956	90,984	98,821

Note: Minor differences due to rounding.

1.7 OPERATING

Operating expense includes gross Operating and Maintenance (O&M) Expense, Capitalized Overhead, Wheeling and Other Income.

1.7.1 Gross O&M Expense

FortisBC's O&M expenditures are required to prudently operate the utility on a safe and reliable basis. The 2012 and 2013 O&M Expense forecasts have been developed in support of the Company's business objectives, ensuring that O&M funding is appropriate and prioritized to meet the needs of customers. The primary objectives of the Company include:

- delivering safe and reliable power at a reasonable cost;
- maintaining or improving customer satisfaction;
- ensuring sound financial management;
- being environmental responsible; and
- planning for demographic and other challenges.

Following is a summary of the Company's O&M budgets:

Table 1.7.1 - FortisBC O&M Budgets by Department (2010-2013)

	DEPARTMENT	2010 Actual	2011 Forecast	Labour Inflation	Other	2012 Forecast	Labour Inflation	Other	2013 Forecast
		($000s)							
1	Power Purchase Management Expense	827	927	-	-	-	-	-	-
2	Generation	2,217	2,187	64	36	2,287	176	35	2,497
3	Utility Operations	13,155	17,412	968	123	18,503	387	74	18,964
4	Mandatory Reliability Standards	-	955	153	71	1,179	8	0	1,187
5	Cominco Facility Charge	46	46	-	(0)	46	-	-	46
6	Brilliant Terminal Station	3,069	2,987	-	173	3,160	-	32	3,192
7	Internal Audit	360	348	72	(24)	396	7	(11)	393
8	Legal & Regulatory	1,451	1,502	8	9	1,520	28	0	1,548
9	Customer Service	5,975	6,412	172	152	6,737	47	22	6,806
10	Community & Aboriginal Affairs	571	594	21	59	674	(7)	22	689
11	Communications	1,067	903	(183)	203	923	11	18	952
12	Human Resources	1,638	1,789	114	(63)	1,840	(41)	75	1,874
13	Information Technology	2,824	2,815	(48)	74	2,841	(45)	49	2,846
14	Health, Safety & Environment	727	907	29	(11)	925	35	(7)	953
15	Facilities Management	3,700	3,620	67	(2)	3,685	8	23	3,716
16	Finance & Accounting	2,617	3,092	38	145	3,275	55	30	3,360
17	Transportation Services	377	766	(226)	33	573	20	(0)	593
18	Supply Chain Management	478	550	(25)	(27)	498	(3)	10	505
19	Corporate & Executive Management	5,049	6,072	15	(975)	5,112	49	513	5,674
20	**TOTAL O&M EXPENDITURE**	**46,148**	**53,885**	**1,239**	**(24)**	**54,172**	**736**	**886**	**55,794**
21	**Power Purchase Management Expense**			**199**	**85**	**1,211**	**34**	**21**	**1,266**
22	**TOTAL O&M EXPENDITURES Prior to reclassification of PPME**	**46,148**	**53,885**	**1,438**	**60**	**55,383**	**770**	**907**	**57,060**

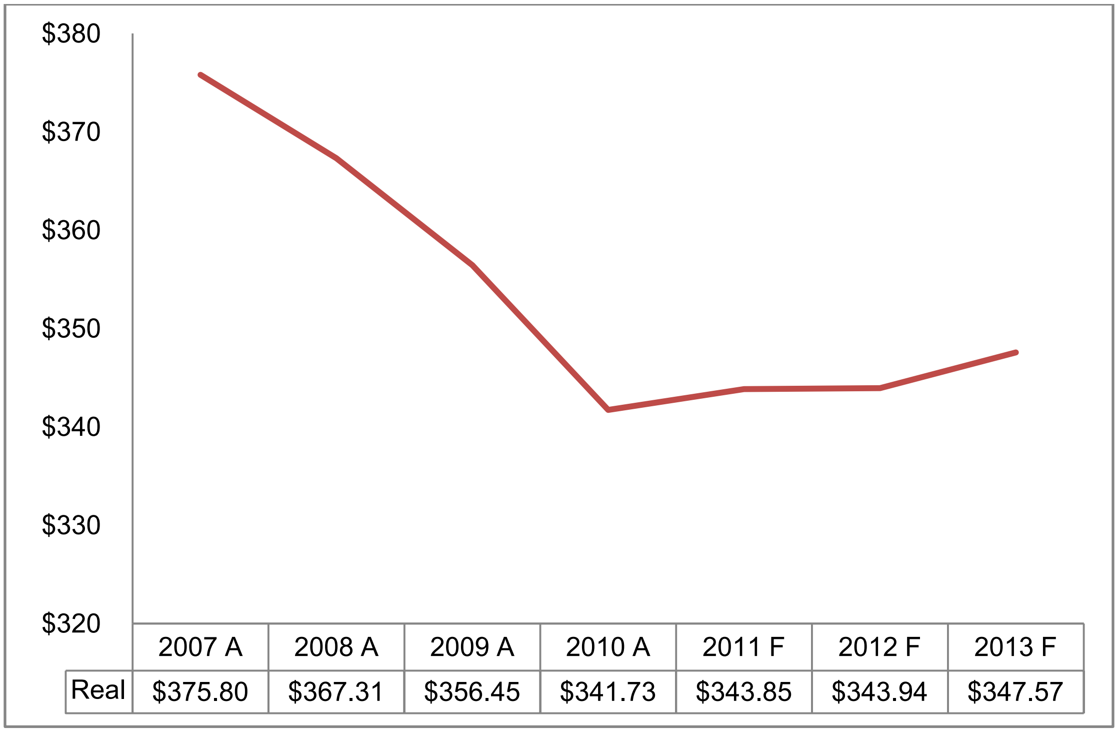
Through the PBR period from 2007 to 2011, the Company has achieved O&M efficiencies of 10.4 percent as a result of the negotiated productivity improvement factors. After factoring out $3.78 million that was transferred from capital to O&M Expense in 2011 as directed by Order G-195-10 concerning the Company's 2011 Capital Expenditure Plan, and those items referred to under the PBR mechanism as extraordinary O&M Expense, the O&M Expense per customer, on a real basis, has declined over the period 2007 to 2013. These efficiencies were achieved while improving or maintaining service levels. FortisBC's customer satisfaction has increased from 70 percent in 2004, when Fortis Inc. acquired the Company, to an average of 87 percent over the past three quarters.

This demonstrates that FortisBC has been successful in managing its O&M expenditures to minimize its impact on customer rates. The 2012 and 2013 increase in O&M Expense impacts customer rates by 0.1 percent and 0.4 percent respectively. These achievements in managing O&M Expense have been made despite a number of changes affecting FortisBC over this period. Some examples of these changes include:

- Changes to government policy in terms of energy use;
- Increased customer expectations;
- Increases in compliance with various regulatory bodies (financial, environmental, etc.);
- Increased requirements for most segments of FortisBC operations; and
- Inflationary pressures.

O&M Expense per customer, on a real (inflation-adjusted) basis can be seen below.

Figure 1.7.1 - Real Base O&M Per Customer



	2007 A	2008 A	2009 A	2010 A	2011 F	2012 F	2013 F
Real	$375.80	$367.31	$356.45	$341.73	$343.85	$343.94	$347.57

1.7.2 Capitalized Overhead

Capitalized Overhead is forecast to be $10.8 million in 2012 and $11.2 million in 2013. The Company has updated the internally prepared capitalized overhead study for the 2012-13 RRA based on 2010 actual financial results and cost drivers. Using the same methodology that has been previously approved, the study initially suggested a 23.9% Capitalized Overhead rate. However, when considering the historical and forecast gross capital expenditures, the Company proposes that the Capitalized Overhead rate applied to Gross O&M should be maintained at 20 percent for the 2012-13 RRA. The details of the Capitalized Overhead study can be found in Tab 4, Section 4.4 of the Application.

1.7.3 Wheeling

Wheeling expense is forecast to increase in 2012 and 2013 by $0.5 million in each year primarily due to increased wheeling nominations at the Okanagan Point of Connection. Wheeling expense is further discussed in Section 4.1 of Tab 4.

1.7.4 Other Income

Other Income is described in detail in Tab 4, Section 4.5 of this Application and includes revenue other than from the sale of electricity. Other Income is forecast to remain relatively stable for the 2011 – 2013 forecast period at between $7.2 and $7.5 million. Other Income is derived from the following sources:

- Apparatus and Facilities Rental;
- Contract Revenue;
- Miscellaneous Revenue;
- Transmission Access Revenue; and
- Investment Income.

1.8 TAXES

1.8.1 Property Taxes

Property taxes are estimated using forecasts of assessed values of taxable assets, municipal mill rates, and taxes paid to municipalities based on revenues earned from electricity consumed within the municipalities. Details can be found in Tab 4, Section 4.6.1 of the Application.

Over the period 2012- 2013, Property Taxes are forecast to escalate at approximately 4 percent or $600,000 per year primarily due to:

- Changes in revenues from electricity expected to be consumed within the municipalities
- Expected increases to assessed property values from normal construction activities driven by capital expenditures on plant and equipment.

1.8.2 Income Taxes

The Company's tax provision (Income Tax Expense) is expected to decrease from approximately $9.4 million in 2011 to $6.1 million in 2012. The estimated decrease in Income Tax Expense from 2011 to 2012 is primarily due to a decrease in Accounting Income (Earnings Before Income Taxes), an estimated increase in income tax timing differences and a reduction in the federal income tax rate. The Company's tax provision is expected to increase to of $7.9 million in 2013. The estimated increase in Income Tax Expense from 2012 to 2013 is primarily due to an increase in Accounting Income, partially offset by an estimated increase in income tax timing differences. Details can be found in Tab 4, Section 4. 6. 2 of this Application.

1.8.3 Harmonized Sales Tax

During 2011, a referendum on whether the provincial voters are in favour of extinguishing the Harmonized Sales Tax (HST) and reinstating the Provincial Sales Tax (PST) is being held, as described further in Section 4.6.3 of this RRA. Should the HST be extinguished, the Company will potentially incur incremental capital and operating costs in order to make the transition back to PST. The Company is proposing to defer any such costs and will request disposition of any deferral account balanced in a future application. Details can be found in Tab 4, Section 4.6.3 of this Application.

1.9 FINANCING

Details of FortisBC's forecast Financing Costs for the period 2010 through 2013 can be found in Section 4.7 of this Application. The Company's Financing Costs consists of:

- Cost of Debt,
- Cost of Equity; and
- Depreciation and Amortization.

Table 1.9 summarizes FortisBC's Financing Cost for the 2010 to 2013 period:

Table 1.9 - Financing Cost 2010 - 2013

	Actual 2010	Approved 2010	Forecast 2011	Forecast 2012	Forecast 2013
			($000s)		
CAPITALIZATION					
Debt	548,917	655,945	642,718	687,152	727,309
Common Equity	396,927	437,296	428,479	458,101	484,872
	945,844	1,093,241	1,071,197	1,145,253	1,212,181
Equity as % of Total	42%	40%	40%	40%	40%
EARNED RETURN					
Interest Expense	35,138	40,506	39,364	41,320	43,553
Net Earnings	38,293	43,292	45,922	45,352	48,002
	73,431	83,798	85,286	86,672	91,555
RETURN ON CAPITAL					
Weighted Average Cost of Debt	6.40%	6.18%	6.12%	6.01%	5.99%
Return on Equity	9.65%	9.90%	10.72%	9.90%	9.90%
Weighted Average Cost of Capital	7.76%	7.67%	7.96%	7.57%	7.55%

Pursuant to Commission Order G-58-06 the Company maintains a capital structure of 60 percent debt and 40 percent equity.

The Cost of Debt is a function of the Company's investment in Rate Base, the Company's capital structure and the Weighted Average Cost of Debt which is forecast to be 6.01 and 5.99 percent for years 2012 and 2013 respectively. Approximately 90 percent of FortisBC's Interest Expense for 2012 and 2013 is a result of embedded long-term debt. The balance of Interest Expense includes interest on short term debt associated with the Company's operating credit facility and financing fees.

FortisBC has $15.0 million in Secured Debentures due for redemption on October 16, 2012. The maturity is expected to be funded by draws on the Company's operating credit facility and funds from operations.

The Company forecasts a long-term debt issuance in the last half of 2013 in the amount of $120.0 million with a term of 30 years and an expected coupon rate of 5.90 percent.

The Cost of Equity is determined by the Company's investment in Rate Base, the Company's capital structure, and the allowed Return on Equity (ROE) as approved by the

Commission. This 2012-13 RRA incorporates an ROE of 9.90 percent, calculated as the BC low-risk utility benchmark ROE (9.50 percent) plus FortisBC's 40 basis points risk premium, approved by Commission Order G-58-06.

The Company forecasts that Depreciation and Amortization will increase from approximately $41.8 million in 2010 to approximately $53.2 million by 2013 primarily due to increases in Rate Base resulting from Company's capital expenditure program from prior years and to changes in deferred charges.

For the period 2007 to 2011, Depreciation was based on a composite rate of 3.2 percent as approved by Order G-58-06. FortisBC has prepared its 2012-13 RRA based on the results of an updated Depreciation Study (2011 Depreciation Study), included in Appendix J, which recommends a composite depreciation rate of 3.2 percent.

1.10 INCENTIVE SHARING

Under the terms of the 2007 – 2011 PBR Plan, Flow-Through Adjustments in certain approved revenues and costs as compared to the forecast will be recovered from or refunded to customers. In addition, variances in the actual ROE as compared to the Company's approved ROE (after being adjusted for certain revenue and cost variances) are shared with customers. ROE Sharing Incentives, positive or negative, up to a 2 percent collar around the approved ROE will be shared equally between customers and FortisBC.

The Combination of Prior Year Incentive True-Ups, Flow-Through Adjustments and ROE Sharing Incentives will serve to reduce 2012 Revenue Requirements by approximately $5.4 million. Details can be found in Tab 4, Section 4.8 of this Application.

2012 – 2013 Revenue Requirements
(2012-13 RRA)

Tab 2
Accounting Policy

June 30, 2011

FortisBC Inc.

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2.0 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (GAAP) USED IN DETERMINING REVENUE REQUIREMENTS

This Application has been prepared using accounting policies and estimates assuming the continuation of Part V of the Canadian Institute of Chartered Accountants Handbook – *Pre-Changeover Canadian Generally Accepted Accounting Principles* (pre-changeover CGAAP) with one exception related to employee future benefits (i.e. pensions and other post-employment benefits) discussed below. Pre-changeover CGAAP was the basis for the preparation of the approved 2011 Revenue Requirements Application (RRA) and previous regulatory applications during the Performance Based Regulation (PBR) term. However beginning in 2012 pre-changeover CGAAP will be withdrawn by Canadian standard setters and will cease to exist as a financial reporting option. This leaves two available options; generally accepted accounting principles in the United States (US GAAP) or International Financial Reporting Standards (IFRS). The accounting policies included in pre-changeover CGAAP, including the ability to recognize rate regulated accounting, are generally consistent with US GAAP for regulatory purposes, with the exception of the accounting for employee future benefits.

As discussed above, the only exception to pre-changeover CGAAP for this 2012-13 RRA is that FortisBC has prepared its deferred charges and cost of service relating to employee future benefits in accordance with US GAAP. While the Commission has not yet approved US GAAP for regulatory purposes, preparing the employee future benefits in accordance with US GAAP is necessary to achieve greater consistency with pre-changeover CGAAP, and due to the inability to continue to apply pre-changeover CGAAP effective 2012. In summary, this 2012-13 RRA has essentially been prepared in compliance with US GAAP for regulatory purposes.

Based on the similarities to pre-changeover CGAAP and the ability to recognize rate-regulated accounting, on February 9, 2011 the Fortis BC Utilities (comprised of FortisBC Inc., Terasen Gas Inc. (now Fortis BC Energy Inc.), Terasen Gas (Vancouver Island) Inc. (now Fortis BC Energy (Vancouver Island) Inc.), and Terasen Gas (Whistler) Inc. (now Fortis BC Energy (Whistler) Inc.)) filed an application requesting approval for the use of US GAAP (the US GAAP Application) in the determination of rates as of January 1, 2012. Specifically, the application sought approval for:

1. The use of US GAAP for the calculation of cost of service, revenue requirements, rate base, and the preparation of regulatory schedules and filings effective January 1, 2012; and
2. Recognition of the one-time conversion costs of approximately $0.8 million. The Company has included these costs in a rate base deferral account in 2011 and is requesting approval to amortize the costs into rates for 2012 and 2013.

The Fortis BC Utilities (the Companies) filed the application for the adoption of US GAAP once it became apparent that IFRS would not allow the recognition of rate regulated assets and liabilities for external financial reporting. The Companies believe continued recognition of regulatory assets and liabilities best reflects the effect that rate-regulation has on the Companies' financial position and the economic realities of their businesses and the regulatory model they operate under. The only set of accounting standards that currently exists that would allow for regulatory assets and liabilities to continue to be recognized is US GAAP; therefore, US GAAP is the reasonable and prudent accounting standard for the Companies to report under.

FortisBC's parent company and source of equity, Fortis Inc., has decided to proceed with adopting US GAAP for financial reporting and securities filing purposes. This decision means that the Fortis Inc. subsidiaries, including FortisBC, will also be required to prepare financial information in compliance with US GAAP.

The following discussion deals with the impacts on revenue requirements of either adopting US GAAP or implementing a modified version of IFRS that permits deferral accounting (which would not be an acceptable implementation of IFRS for external reporting purposes).

Additionally, FortisBC has included a summary of the current reconciling items between regulatory reporting and external financial statements as Appendix D: Financial Reconciliations from 2010 BCUC Annual Report, to provide some background around the level of reconciliation that is currently required under pre-changeover CGAAP.

2.1 ADOPTION OF US GAAP FOR RATE SETTING PURPOSES

The adoption of US GAAP for rate setting purposes has fewer adjustments than adopting IFRS and is closer to the existing reporting under pre-changeover CGAAP. The Fortis BC Utilities have committed to adopting US GAAP for external financial reporting and by way of the US GAAP Application have also requested the adoption of US GAAP for rate setting purposes.

The following is a discussion of the main differences identified to date between US GAAP and FortisBC's existing regulatory policies and treatments. These differences pertain to Pension and Other Post-Employment Benefits, Uncertain Tax Positions (which are not expected to have an effect on cost of service at this time) and the Costs Associated with the Adoption of US GAAP (which were requested for deferral in the US GAAP Application).

2.1.1 Pension and Other Post-Employment Benefits

The primary changes include the adoption date of employee future benefits, recognition of the funded status on the balance sheet and the change of the measurement date, as discussed below.

a) Adoption Date of Employee Future Benefits Accounting for US GAAP and Transitional Obligation

The Canadian Institute of Chartered Accountants (CICA) adopted accrual accounting for Pension and other Post-Employment Benefits (OPEB) starting on January 1, 2000. This resulted in recognizing a transitional benefit (obligation) which has been amortized into pension net benefit cost over the Expected Average Remaining Service Life (EARSL). The equivalent standards at the time under US GAAP were Financial Accounting Standards Board (FASB) Statement 87 *Employers' Accounting for Pensions* (FAS 87) and Statement 106 *Employers' Accounting for Post-Retirement Benefits Other Than Pensions* (FAS 106). It would not be feasible for FortisBC to obtain actuarial data prior to 2000 and as such, there is an accommodation available to foreign registrants who are adopting US GAAP, which would include FortisBC. The accommodation essentially allows for the calculations of net benefit cost for pension and OPEBs to be calculated from 2000 onwards except for the transitional benefit (obligation) created on adoption of Canadian GAAP. The transitional benefit (obligation) that was created in 2000 when Canadian GAAP adopted accrual accounting for pension defined benefit plans and OPEBs is moved back to 1989 and assumed to be amortized from that period onwards.

As described in the Tab 5, Section 5.4 – Deferred Charges and Credits, FortisBC has proposed the creation of pension and OPEB rate base deferral accounts to capture the remaining historical cumulative difference that still exists between CGAAP and US GAAP net benefit costs as of January 1, 2012. The specific deferral accounts referred to in the deferred charges schedule are the "US GAAP Pension Transitional Obligation" and the "US GAAP OPEB Transitional Obligation". The Company has proposed the recovery for both of these transitional amounts over the approximate EARSL of 12 years, to phase the transitional difference into rates.

Assuming the same EARSL amortization period for the respective transitional adjustments, the total employee future benefit expenses for 2012 and 2013 are expected to be lower under US GAAP as compared to a scenario where IFRS with deferral accounting is permitted. Additionally, the total employee future benefit expenses for 2012 and 2013 are expected to be lower under US GAAP as compared to pre-changeover CGAAP, although this standard has ceased to exist as a reporting option beginning in 2012 and is presented for comparative purposes only.

The following table compares the total pension and OPEB expenses for 2012 and 2013 under US GAAP as compared with both modified IFRS with deferral accounting and pre-changeover CGAAP.

Table 2.1.1 - Pension and OPEB Expense under US GAAP vs. IFRS with Deferral Accounting vs. Pre-Changeover CGAAP

		2012			2012	
		US GAAP	IFRS	Difference to US GAAP	CGAAP***	Difference to US GAAP
			($000s)			
1	FRIP	489	(252)	(741)	919	430
2	IBEW Plan	2,343	1,677	(666)	2,745	402
3	COPE Plan	1,520	1,333	(187)	1,549	29
4	Supplemental Plans	339	330	(9)	356	17
5	Pension net benefit cost	4,691	3,088	(1,603)	5,569	878
6	Amortization of pension transitional amount	183	2,038	1,855	-	(183)
7	**Total Pension expense**	**4,874**	**5,126**	**252**	**5,569**	**695**
8						
9	OPEB net benfit cost	2,726	2,379	(347)	3,047	321
10	Amortization of 2005 CICA OPEB liabilty	480	480	-	480	-
11	Amortization of OPEB transitional amount	164	446	282	-	(164)
12	**Total OPEB expense**	**3,370**	**3,305**	**(65)**	**3,527**	**158**
13						
14	**Total Employee Future Benefits expense**	**8,243**	**8,431**	**187**	**9,096**	**853**

		2013			2013	
		US GAAP	IFRS	Difference to US GAAP	CGAAP***	Difference to US GAAP
			($000s)			
1	FRIP	188	(432)	(620)	277	89
2	IBEW Plan	2,036	1,501	(535)	2,183	147
3	COPE Plan	1,471	1,323	(148)	1,498	27
4	Supplemental Plans	344	344	-	345	1
5	Pension net benefit cost	4,039	2,736	(1,303)	4,303	264
6	Amortization of pension transitional amount	183	2,038	1,855	-	(183)
7	**Total Pension expense**	**4,222**	**4,774**	**552**	**4,303**	**81**
8						
9	OPEB net benfit cost	2,825	2,529	(296)	3,145	320
10	Amortization of 2005 CICA OPEB liabilty	480	480	-	480	-
11	Amortization of OPEB transitional amount	164	446	282	-	(164)
12	**Total OPEB expense**	**3,469**	**3,455**	**(14)**	**3,625**	**157**
13						
14	**Total Employee Future Benefits expense**	**7,690**	**8,229**	**538**	**7,928**	**238**

**** CGAAP has been presented for comparative purposes only and has ceased to be a reporting option for employee future benefits beginning in 2012.*

The net effect under each scenario presented above show that the effect of adopting US GAAP has a lower total cost for total employee future benefits expense compared to adopting IFRS with deferral accounting and pre-changeover CGAAP for 2012 and 2013.

b) Recognition of Funded Status on Balance Sheet

Under US GAAP Accounting Standards Codification (ASC) 715-60-25, *Defined Benefit Plans, Other Post-Retirement – Recognition*, the funded status of benefit plans – measured as the difference between the fair value of plan assets and the benefit obligation – is required to be recognized on the balance sheet of the entity. This means that the pension benefit obligation shall be the projected pension benefit obligation and for OPEB plans, the OPEB obligation shall be the accumulated post-employment benefit obligation. In companies not subject to rate regulation, the recognition of the funded status has a corresponding adjustment to Accumulated Other Comprehensive Income (AOCI). The accumulated balance residing in AOCI is representative of deferred plan costs and income, including unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transitional obligation or asset. These amounts are deferred in AOCI and through time will continue to be recognized as a component of net benefit cost.

Under a US GAAP adoption scenario, rather than recognize this balance through AOCI or as a Rate Base Deferral Account, the Company is requesting approval to recognize a non-rate base deferral account to accumulate these amounts as indicated in Tab 7, Schedule 1 – A and Appendix E – Accounting Changes: US Generally Accepted Accounting Principles (US GAAP) and Request for Non-Rate Base Deferrals. Under current US GAAP, the amortization of the AOCI amount is recycled back through the pension net benefit cost, which is why the AOCI amount is not requested to be included as an amortizing rate base deferral account. The recognition of the funded status and AOCI is simply a re-classification between the pension obligation and a deferral account that occurs at the external financial reporting level.

c) Measurement Date

US GAAP, like IFRS, requires that defined benefit plans use a measurement date coinciding with the fiscal year end of the Company. For 2011 and prior years, FortisBC measured its defined benefit plans as at September 30, which is permitted under pre-changeover CGAAP CICA 3461 and is three months prior to the balance sheet date of December 31. In order to comply with US GAAP, the Company will be changing its measurement date to December 31 for the fiscal year beginning January 1, 2012. The three month "stub period" from October 1, 2011 to December 31, 2012 has been included as part of the US GAAP Pension and OPEB Transitional Obligation deferral accounts requested for approval in Tab 5, Section 5.4 – Deferred Charges and Credits. The changes to employee future benefit assets and obligations during this "stub period" have been included as part of the amortization of the related deferral accounts into the forecast future employee future benefit expenses as previously discussed.

2.1.2 Uncertain Tax Positions

FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes* (later codified as ASC 740-10-55) was implemented in 2006 and was intended to reduce uncertainty in accounting for income taxes. The standard requires a series of steps for the recognition, measurement, disclosure and presentation of uncertain tax positions. The accounting and reporting requirements of FIN 48 involve a two-step process that may result in a larger income tax liability due to the earlier recognition of income tax liabilities. The standard was implemented to reduce the uncertainty and diversity in practice that the FASB had observed which resulted in non-comparability across companies. No similar standard exists under either existing CGAAP or IFRS.

FIN 48 requires that FortisBC have documentation and support for each adjustment made to reconcile between accounting income and taxable income. The areas of documentation have included such items as the allowance for doubtful accounts, meals and entertainment expenses, unpaid compensation, inventory obsolescence, capitalized overheads, capital additions for tax purposes, dismantling costs and deferred charges.

While there are many items to document and FortisBC is still at the documentation stage, the Company does not expect to have any material adjustments as a result of this standard. The documentation is still subject to audit and the audit may result in adjustments to positions and ultimately to the recognition of amounts under this standard.

As a result, under a US GAAP adoption scenario and described further in Appendix E - Accounting Changes: US Generally Accepted Accounting Principles (US GAAP) and Request for Non-Rate Base Deferrals, FortisBC would propose the creation of a Non-Rate Base Deferral Account to capture any differences that may arise from the implementation of FIN 48.

2.1.3 Other US GAAP Items

A number of other adjustments are contemplated on transition to US GAAP that should not affect cost of service or rate base. These potential adjustments include the application of pushdown accounting and recognizing the Brilliant Power Purchase Agreement (BPPA) as a capital lease for external financial reporting purposes. The BPPA was also expected to qualify as a capital lease under IFRS as indicated in Appendix B to the 2011 Preliminary Revenue Requirements Application. Further details on the BPPA as a capital lease are explained in Appendix E. None of these transactions are expected to affect regulatory accounting or reporting and would not affect the revenue requirement.

2.1.4 Costs Associated with the Adoption of US GAAP

In the US GAAP Application, FortisBC outlined the expected costs of adopting both IFRS and US GAAP. The costs of adopting US GAAP included in the US GAAP Application for FortisBC included estimated incremental one-time conversion costs of $0.8 million and $0.3 million of ongoing costs to maintain US GAAP. Since that time, the Fortis BC Utilities' parent, Fortis Inc., filed a confidential application with the Ontario Securities Commission (OSC) seeking exemptive relief for its reporting issuer subsidiaries which included FortisBC Inc. and FortisBC Energy Inc. On June 9, 2011, the OSC issued its Decision on the Exemption application, granting the relief sought for the financial years commencing on or after January 1, 2012 but before January 1, 2015.

As a result FortisBC has reviewed the estimated conversion costs and has revised those cost estimates in order to reflect the avoided costs resulting from the receipt of the OSC Exemption. In addition, FortisBC has updated the remaining cost estimate items with the most recent expectations. While some of the remaining costs have decreased, they have been generally offset by increases in accounting costs to reflect the complexity of certain of the accounting issues encountered relating to the Company's power purchase arrangements. Overall, there are no significant changes to the one-time conversion costs for rate-setting purposes, while the ongoing costs are expected to decrease by approximately $0.1 million. Therefore, the following has been included in this 2012-13 RRA:

- The one-time incremental costs of approximately $0.8 million are estimated to result from legal, auditor and consulting fees to adopt US GAAP. The US GAAP one-time incremental conversion costs have been included as a Rate Base Deferral Account in the 2012-13 RRA in Tab 5, Section 5.4 – Deferred Charges and Credits;
- The revised $0.2 million of on-going costs under US GAAP, which consist of auditor fees, would replace those expenses currently incurred under pre-changeover

CGAAP. These forecast US GAAP ongoing costs have been included in the Finance operating expenses included in Section 4.3.4.15 of Tab 4 to this 2012-13 RRA.

2.2 IFRS WITH DEFERRAL ACCOUNTS FOR RATE SETTING PURPOSES

If FortisBC adopted IFRS for both rate setting purposes and external financial reporting, there would be a significant number of reconciling items between external financial reporting and regulatory reporting. This would be due to the inability to recognize regulatory assets and liabilities under IFRS for external financial reporting, creating a significant increase in the reconciliation process between regulatory reporting and financial reporting. Over the course of a number of years, this reconciliation would become more complicated as certain deferrals are recovered from customers while others would continue to build through time.

2.2.1 Changes to Fully Implement IFRS

Even under a scenario where IFRS with deferral accounts is adopted for rate setting purposes only, several changes would be required to the current accounting treatment included in the 2012-13 RRA. On the adoption of IFRS, all regulated assets, liabilities and items currently classified as Deferred Charges would need to be de-recognized for external financial reporting as current IFRS does not recognize the effects of rate regulated accounting. Once adopted, any impacts of rate regulation that are included or embedded in other assets or liabilities could not be recognized on a go forward basis.

While Appendix F of this 2012-13 RRA discusses in more detail the required changes for adopting IFRS for regulatory purposes, a summary of these changes are as follows:

1. **Pension and Other Post-Employment Benefits expenses** – is a key difference under IFRS for regulatory purposes. The total employee future benefits expense as determined under IFRS are compared in Section 2.1 above and the creation of new deferral accounts as described in Tab 5, Section 5.4 – Deferred Charges and Credits. Additionally, the current method of recognizing actuarial gains and losses through pension expense is being re-examined by the International Accounting Standards Board (IASB). If the current policy on the corridor method is removed from IFRS, the recognition of the effect of actuarial gains and losses would be required in the current period rather than deferring the effects by the use of the corridor method.
2. **Capitalized Overhead** - The rate of overheads capitalized that would be permitted for inclusion in property plant and equipment would be limited to the rate that would

be considered "directly attributable" under IAS 16. The overheads study filed in this RRA in Tab 4, Section 4.4, proposes a 20 percent capitalized overhead rate. Any difference between this rate and a rate that is analyzed as meeting the criteria of directly attributable under IFRS would require recognition in a rate base deferral account for regulatory purposes rather than as part of property plant and equipment.

3. **Allowance for Funds Used During Construction (AFUDC)** - FortisBC would be unable to recognize AFUDC under IFRS. Similar to the treatment of capitalized overhead rate differences, differences between the AFUDC rate and an allowed interest during construction rate as determined under IFRS would need to be recognized in a rate base deferral account for regulatory purposes, rather than as part of property, plant and equipment.

4. **Timing of depreciation** - IFRS specifically requires that depreciation of assets commence when an asset is available for use, while FortisBC depreciates based on the annual opening balance as required under the BCUC Uniform System of Accounts. The difference between the depreciation expenses used for regulatory purposes compared to the depreciation expenses calculated when an asset is available for use would need to be recognized in a rate base deferral account for regulatory purposes.

5. **Property, plant and equipment and intangible assets presentation** - On the adoption of IFRS, accumulated depreciation and amortization is required to be netted against the gross book value to effectively reset the cost of property, plant and equipment and intangible assets on transition. This re-setting would not be expected to affect the depreciation expense included in this RRA, although the presentation of assets and depreciation rates could be impacted. However there would be the expectation to incur costs to modify accounting information systems to permit this presentation change.

2.2.2 Costs associated with the adoption of IFRS

In the US GAAP Application, FortisBC outlined the expected costs of adopting both IFRS and US GAAP in 2011. The costs of adopting IFRS for FortisBC included estimated incremental one-time conversion costs of $0.6 million and $0.4 million of ongoing costs to maintain IFRS. The $0.6 million one-time incremental costs were estimated to result from legal, auditor and consulting fees to adopt IFRS. The $0.4 million of on-going costs under

IFRS, which consist primarily of auditor fees and incremental staffing resources, would replace those expenses currently incurred under pre-changeover CGAAP. These costs have not been included in this Application as the FortisBC 2012-2013 RRA has been prepared in accordance with pre-changeover CGAAP with the inclusion of employee future benefits recognized under US GAAP.

2.3 SUMMARY OF STATUS OF GAAP

In summary, FortisBC has prepared this 2012-13 RRA in accordance with pre-changeover CGAAP, which is generally consistent with US GAAP, as well as the determination of employee future benefits under US GAAP and the inclusion of the US GAAP incremental one-time conversion costs. While adoption of US GAAP for regulatory purposes has not yet been approved by the Commission, it is necessary to forecast employee future benefit expense under US GAAP as pre-changeover GAAP has been withdrawn by Canadian standard setters and will cease to exist as a financial reporting option beginning in 2012. This means that this 2012-13 RRA is essentially a US GAAP compliant Application. In the event that FortisBC is ordered to implement accounting policies other than US GAAP, the Company will file an evidentiary update to include the impacts of those changes.

2012 – 2013 Revenue Requirements Application
(2012-13 RRA)

Tab 3
Load and Customer Forecast

June 30, 2011

FortisBC Inc.

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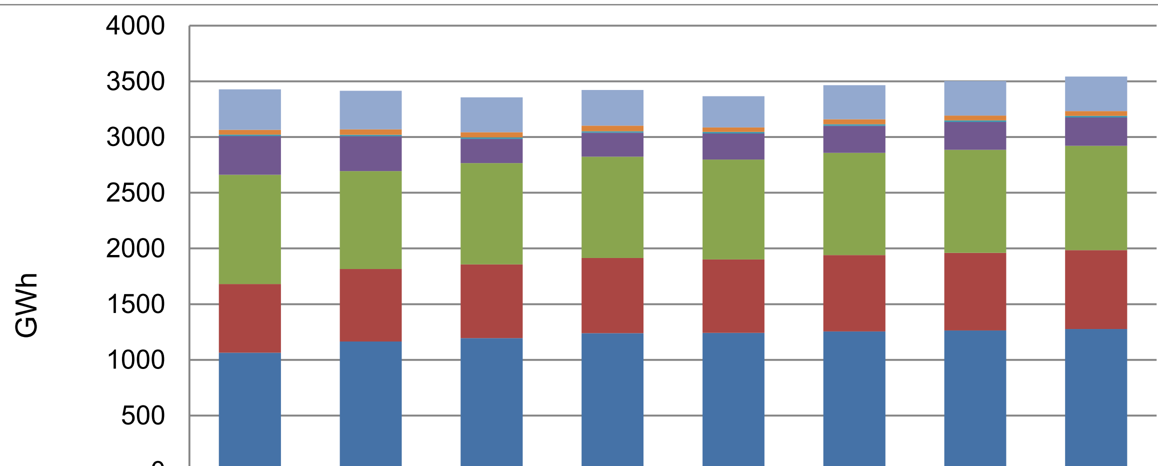
3.0 2012 AND 2013 FORECAST

Gross system energy load is a mix of residential, commercial, wholesale, industrial, street lighting and irrigation loads and system losses. The residential, commercial and wholesale loads represent the largest portion of these forecasts at 82 percent. The industrial loads are about 7 percent of gross load. For 2012 and 2013 gross system losses are forecast at 8.82 and 8.76 percent, using a two year rolling average from actual system loss calculation and forecast loss reduction in 2013 because of Advanced Metering Infrastructure (AMI) based programs. Gross system load is forecast to be 3,502 and 3,543 GWh in 2012 and 2013 respectively, equalling 1.1 percent and 1.2 percent increases. The load increase forecast for 2012 and 2013 is related mainly to increases in the residential, wholesale and commercial sectors. FortisBC's allocation of normalized gross energy load actual for the years 2006 to 2010 and forecast for 2011 to 2013 is shown in the chart below.

Figure 3.0 - Normalized Gross Load Composition



	2006	2007	2008	2009	2010	2011	2012	2013
Loss	364	346	313	321	280	306	309	310
Irrigation	43	48	46	49	40	44	44	43
Lighting	13	13	13	13	14	14	14	14
Industrial	348	314	218	216	234	243	250	255
Wholesale	980	879	909	909	897	918	926	935
General Service	616	650	661	675	660	685	696	709
Residential	1064	1165	1196	1239	1242	1255	1264	1276

The 2012 and 2013 load forecast for the industrial sector is based on customer supplied forecasts and British Columbia Gross Domestic Product (GDP) forecasts for the individual industrial sectors from the Conference Board of Canada (CBOC). Weather normalized loads underlie the Residential and Wholesale classes forecast while actual loads are used for the remaining classes. Reductions in energy consumption due to incremental demand side management (DSM) programs introduced after 2010 are forecast to be 53 GWh in 2012 and 89 GWh in 2013. Other savings include Residential Inclining Block (RIB) and AMI based revenue protection program savings. All forecast values in this report are shown after being reduced for these DSM and other savings, if not explicitly stated otherwise.

The winter peak is forecast at 721 MW in 2012 and 731 MW in 2013, while the summer peaks are forecast at 567 MW in 2012 and 575 MW 2013.

The total number of direct customer accounts at the end of 2012 and 2013 are projected to be 116,105 and 118,357, or a 1.9 percent increase each year. The table below summarizes energy requirements, seasonal peak demands and customer growth for 2011, 2012 and 2013.

Table 3.0 - Forecast Summary (Normalized)

	Energy Sales (GWh)	Approved 2011	Forecast 2011	Forecast 2012	Forecast 2013
1	Net Load	3,162	3,159	3,193	3,233
2	Losses	310	306	309	310
3	Gross Load	3,472	3,465	3,502	3,543
4	Gross Loss Percentage	8.94%	8.82%	8.82%	8.76%
	System Peak (MW)				
5	Winter Peak	723	710	721	731
6	Summer Peak	578	560	567	575
	Year-End Direct Customer Count				
7	Total Customers	114,336	113,977	116,105	118,357
8	Percentage Change	1.8%	1.5%	1.9%	1.9%

3.1 ECONOMIC OUTLOOK

GDP growth in 2011 is expected to be 2.0 percent due to restrained government spending and a slowdown in the domestic housing market in Canada and the US. However, real GDP is expected to rise by 3.0 percent in 2012 and 3.2 percent in 2013. This increase is due to renewed strength in the forestry, housing, and export markets which will be driving economic growth. Over the long run the CBOC is forecasting a moderate increase in GDP.

Provincial housing starts were up in 2010 mainly due to the Vancouver Olympics, and are forecast to slow down in 2011. For 2012 and 2013 the CBOC is forecasting that housing starts will return to positive growth because of renewed strength in the housing market. Some of this renewed strength is due to forecast declining unemployment rates due to economic growth in the province.

The forestry industry has been suffering for the past couple years due to a sharp decline in housing starts in the US and Canada. With the US economy strengthening and increased demand from China, this sector is expected to improve its exports and overall position in 2012 and 2013. GDP growth rate for the forestry industry is forecast to be 5.2 percent in 2012 and 3.6 percent in 2013.

Table 3.1 - CBOC – Forecast of Growth Rates for British Columbia

	2010	2011	2012	2013
GDP				
British Columbia	4.1%	2.0%	3.0%	3.2%
Forestry	15.5%	2.9%	5.2%	3.6%
Commercial Services	4.6%	1.4%	3.0%	3.2%
Manufacturing	6.0%	4.3%	4.1%	3.8%
Utilities	1.1%	1.2%	3.2%	3.5%
Housing Starts	64.7%	(4.5%)	18.7%	5.2%

Note: These numbers were issued in spring 2011

3.2 WEATHER NORMALIZATION

In order to forecast temperature sensitive loads, it is necessary to eliminate the contribution of extreme weather effects on load growth prior to performing any statistical analysis. This is accomplished through temperature normalization, which adjusts temperature sensitive loads to correspond to a reference temperature. The Residential and Wholesale classes are the only ones to exhibit significant correlation of usage to temperature.

The 2012 and 2013 energy forecast is based on monthly 10-year average heating and cooling degree days (HDD and CDD) provided by Environment Canada. These are used to define the normal temperature. A normalization model calculates sensitivity factors that relate to the HDD and CDD to sales and then uses the results to normalize the actual loads. For more detailed information regarding weather normalization please refer to Appendix 3B.

3.3 DEMAND SIDE MANAGEMENT AND OTHER ADJUSTMENTS

Incremental DSM savings are forecast by customer class and deducted from the before-DSM forecasts. Residential energy sales are further adjusted by forecast reductions in usage expected to follow the implementation of a RIB rate beginning in 2012, offset by increased (recovered) sales enabled by the implementation of the Company's AMI project beginning in 2013. All forecast load values in this report are shown after being adjusted by incremental DSM and these other factors.

3.4 METHODOLOGY OVERVIEW

Customer and load forecasts are based on total provincial trends and expectations. The 2012 and 2013 forecast is based on GDP and housing start projections produced for the province by the CBOC, as well as load growth and survey information. FortisBC uses the following main inputs for determining customer and sales growth:

- Relationship of residential customer growth to housing starts;
- Relationship of the wholesale and commercial class sales to GDP;
- Forecast GDP growth rates for industrial sectors and load surveys;
- Trend analysis for lighting loads.

3.4.1 Residential

Residential demand is influenced by home characteristics, household consumption patterns, type of housing and weather. Before-DSM energy requirements for the residential class are determined by

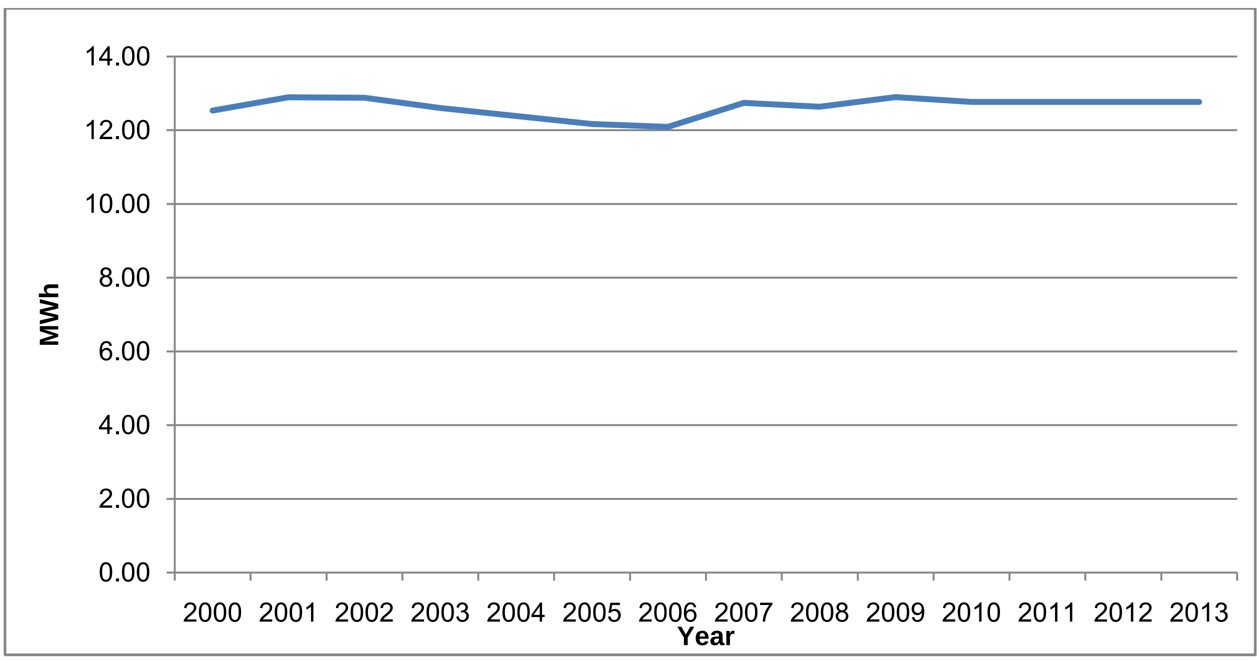
- The annual average residential customer counts; and
- The normalized Residential Use Per Customer (UPC).

Forecast after-DSM energy requirements are obtained by subtracting incremental DSM savings, as well as the other adjustments identified in Section 3.3 above, from the before-DSM energy forecast.

Determination of residential customer growth begins with a review of past customer growth. Forecast residential customer counts are determined from a twenty year regression of the year-end customer accounts on Provincial housing. This equation can be found in Appendix 3C. The housing starts forecast is provided by the CBOC. The number of residential accounts has been increasing slowly in 2011, reflecting the slower than anticipated economic recovery of the province. The 2011 customer count is forecast to increase by 1,574 new residential customers, which is a 1.6 percent increase over 2010. Residential customer growth is forecast to be 1.9 percent in both 2012 and 2013.

The normalized residential UPC is calculated by taking the average of the normalized UPC from the years 2008 to 2010. The before-DSM UPC is then assumed to remain constant from 2011 onward at 12.77 MWh, since there is no statistically valid evidence of either an upward or downward trend.

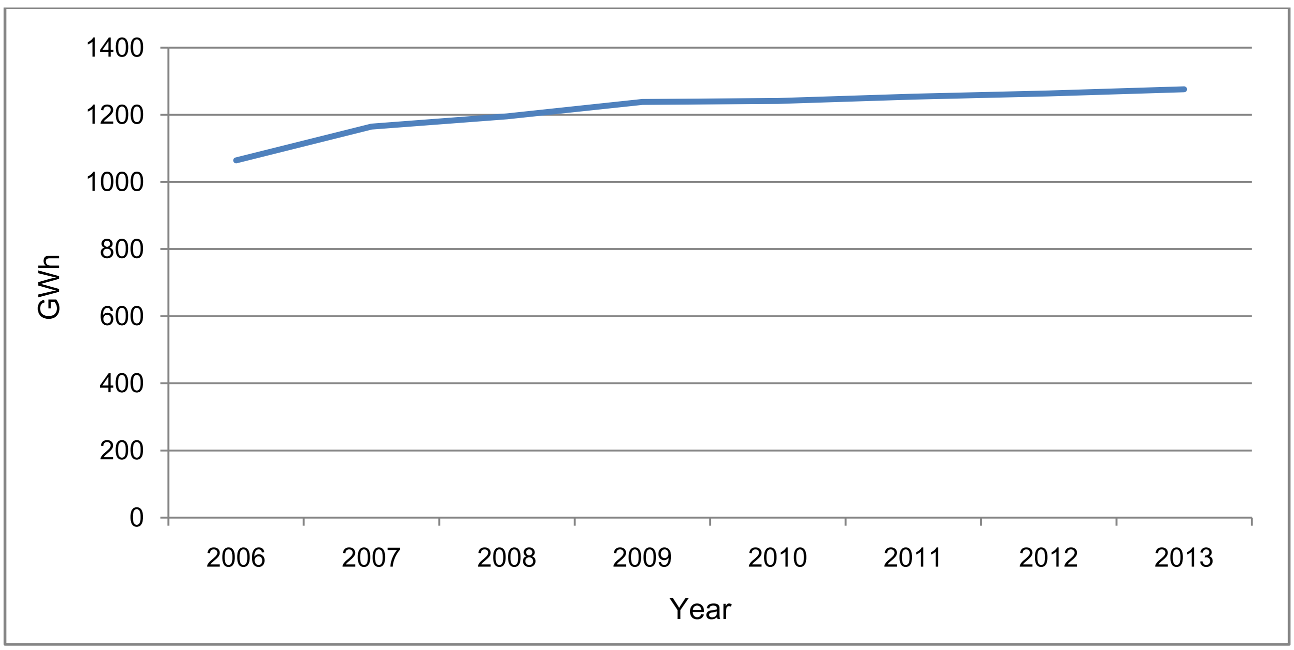
Figure 3.4.1-1 - Normalized and Forecast Residential UPC



FortisBC has conducted residential end use surveys in 1990, 1997 and 2010. These surveys were reviewed with the goal of noting trends in customer usage requirements. The studies indicate that over the twenty year period there has been a small drop in the percentage of dwellings that are single family detached dwellings but that square footage has increased somewhat. Two prominent changes in end uses appear to be a slight increase in the penetration rate of spas and hot tubs and a significant rise in the penetration rate of air conditioning. Both of these would tend to increase consumption. However, there also has been a substantial reduction in the use of electricity for heating domestic hot water, a small decline in electric space heating penetration and the use of compact fluorescent lights bulbs has risen from 0.2 bulbs per home to 11. These factors likely offset consumption gains in other areas. The studies do not appear to provide an indication that future UPC will either rise or fall and hence do not contradict the assumption of constant UPC for load forecasting purposes.

Projected residential loads for 2012 and 2013 are 1,264 GWh and 1,276 GWh. These correspond to a 0.7 percent increase in energy consumption in 2012 and a 1.0 percent increase in 2013.

Figure 3.4.1-2 - Normalized and Forecast Residential Energy Consumption

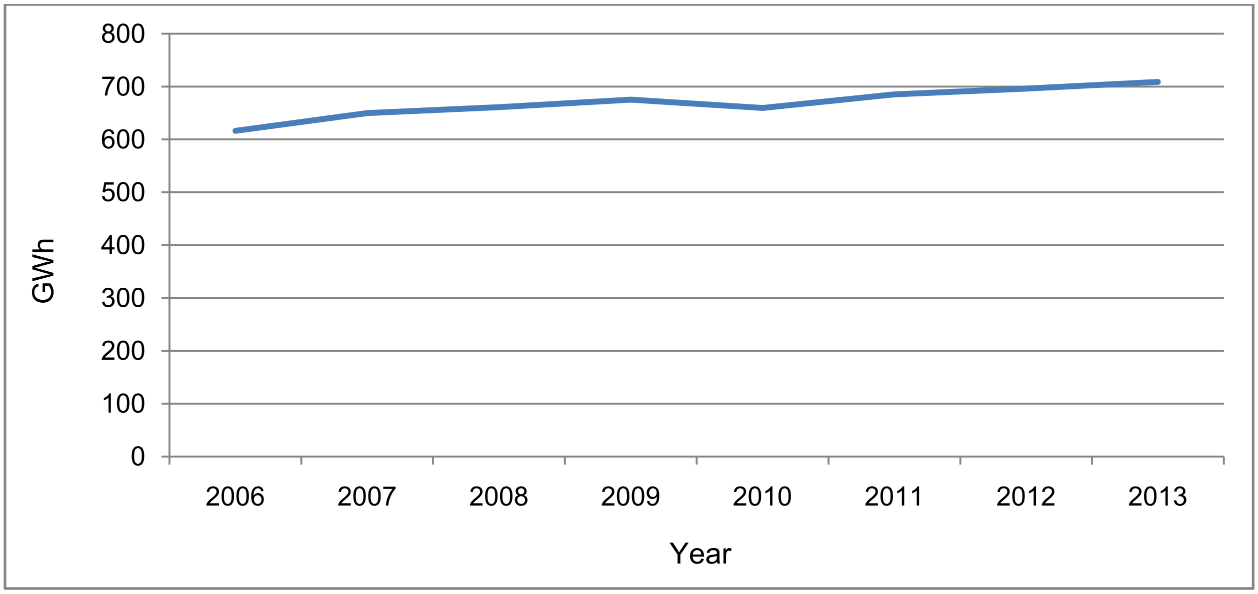


3.4.2 Commercial

The commercial class encompasses a broad range of commercial and small industrial customers as well as schools, hospitals, recreation centers and other public facilities. Energy consumption in this class is closely tied with economic activity; therefore the commercial class is forecast based on the ten year relationship between load and the provincial GDP which can be found in Appendix 3C.

Forecast GDP growth is expected to increase from the 2011 levels of 2.0 percent to 3.0 percent in 2012 and 3.2 percent in 2013; this indicates that the province will be in a better economic position and the commercial class will be producing more goods and services. Sales in this class are forecast to be 696 GWh in 2012 and 709 GWh in 2013. These equate to growth rates of 1.6 percent in 2012 and 1.8 percent in 2013.

Figure 3.4.2 - Actual and Forecast Commercial Energy Consumption



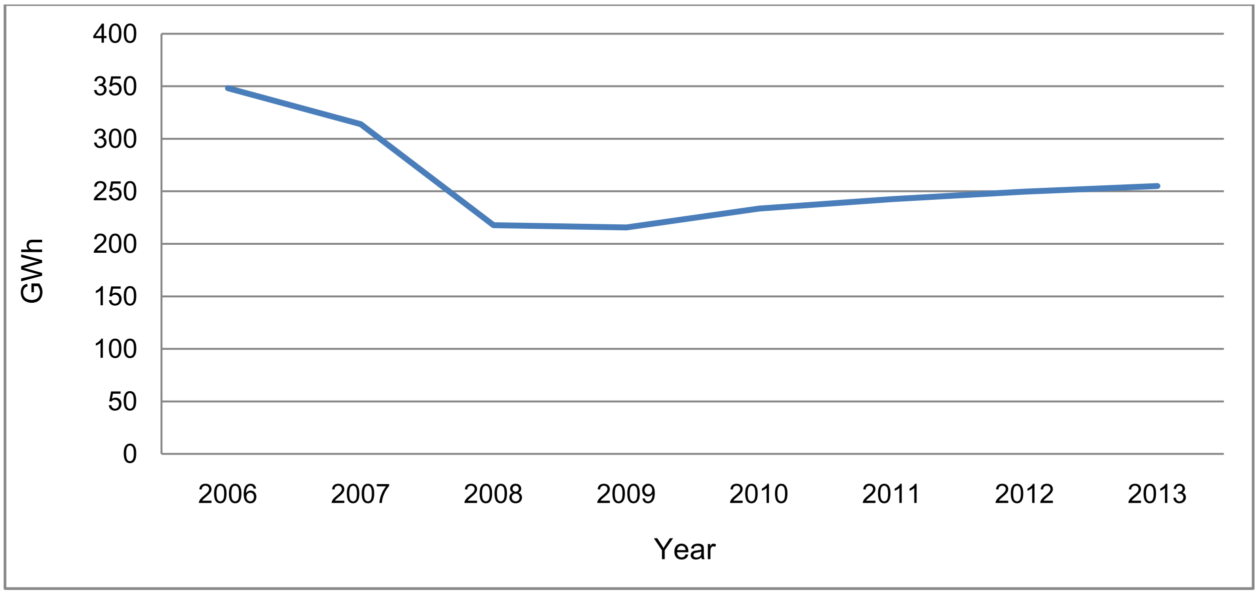
3.4.3 Industrial

Industrial Loads are affected by the level of economic activities such as exports, commodity prices and other factors. Forestry, pulp and sundry sectors make up over one third of FortisBC industrial customers. Other customers include large educational institutions, agriculture, construction, manufacturing and mining. The forecast for this class is determined by a combination of surveys and projections of 2010 loads and the forecast provincial GDP growth rates for individual industries.

Many of FortisBC's industrial customers are in the process of returning to normal operations after the recession starting in 2008, which adversely affected all industrial customers, especially the forestry sector. The forestry industry has compensated for the recession setback in the past few years to some degree by making international deals with China as well as enhancing domestic revenues through biomass opportunities. FortisBC is anticipating that Zellstoff Celgar Limited Partnership's (Celgar) annual load will be about 4 GWh due to its greater self generation that began in 2010.

Load surveys are sent to all industrial customers asking for their anticipated use for the next five years. If the survey is not returned by a customer then the customer's load forecast is obtained by escalating its 2010 load by the forecast GDP growth rates for its specific industry. The GDP growth rate values are from the CBOC. The projected industrial load is 250 GWh for 2012 and 255 GWh for 2013. This is a 3.0 percent increase in 2012 and 2.1 percent increase in 2013.

Figure 3.4.3 - Actual and Forecast Industrial Energy Consumption

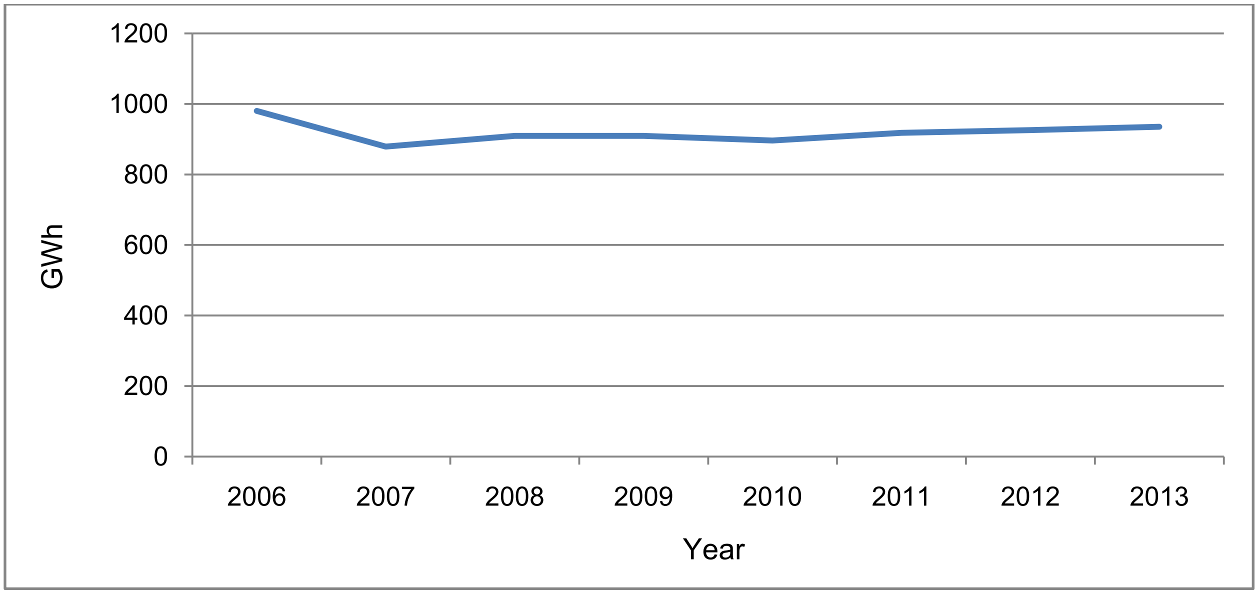


3.4.4 Wholesale

FortisBC sells wholesale power to municipalities within its service territory that own and operate their own electrical distribution systems, as well as to BC Hydro at Lardeau and Kingsgate. The municipal utilities are Penticton, Grand Forks, Kelowna, Nelson and Summerland. These wholesale customers have a load composition that is a mix of residential, commercial, industrial and street light customers, in which the residential and commercial sectors play the main roles. This makes their loads to a large extent sensitive to economic activity.

Forecast growth is based on a ten year regression of normalized load on GDP for the province, the results of which can be found in Appendix 3C. Total forecast 2012 and 2013 wholesale load is projected to be 926 GWh and 935 GWh respectively, which corresponds to a growth rate of 0.8 percent for 2012 and 1.0 percent in 2013.

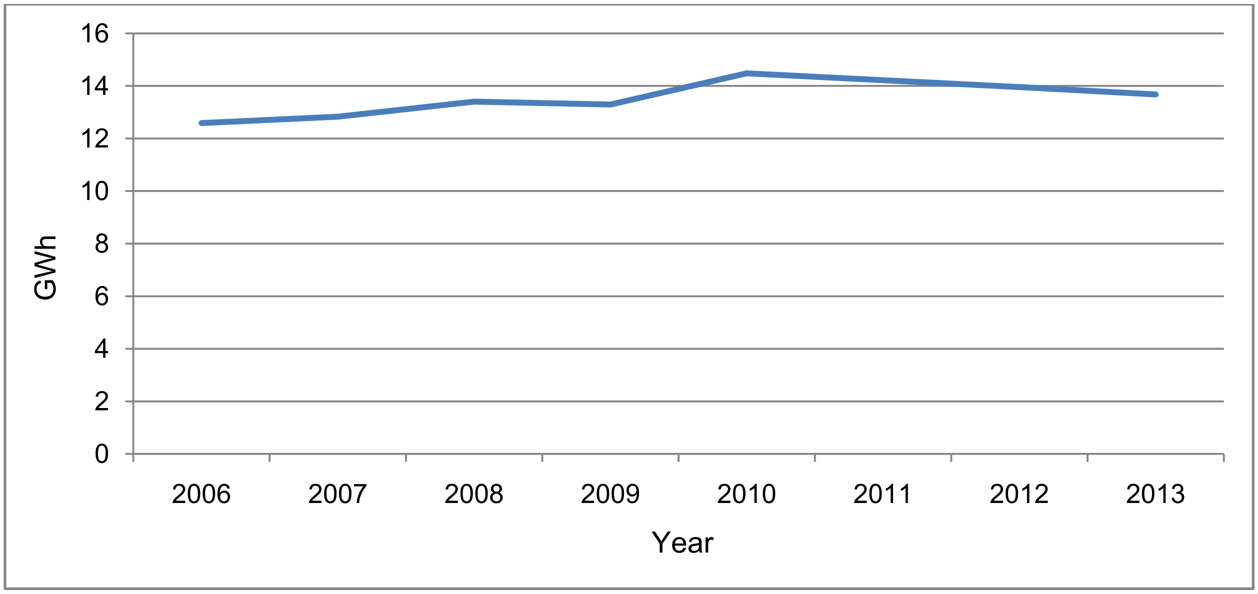
Figure 3.4.4 - Normalized and Forecast Wholesale Energy Consumption



3.4.5 Lighting

Lighting load has been increasing slightly year over year with an average annual increase of 0.5 GWh from 2006 to 2010. New DSM technologies, such as adaptive street lights, have been recently introduced to the FortisBC service area and are expected to counteract the annual load growth. For more detail regarding the lighting load please refer to Appendix 3C. The lighting load forecast is produced by applying trend analysis from 2006 to 2010 and forecasting the load without DSM savings, then adjusting this forecast with the forecast DSM savings. The projected lighting load is 14.0 GWh for 2012 and 13.7 GWh for 2013. This is a 1.8 percent decrease in 2012 and 2.0 percent decrease 2013.

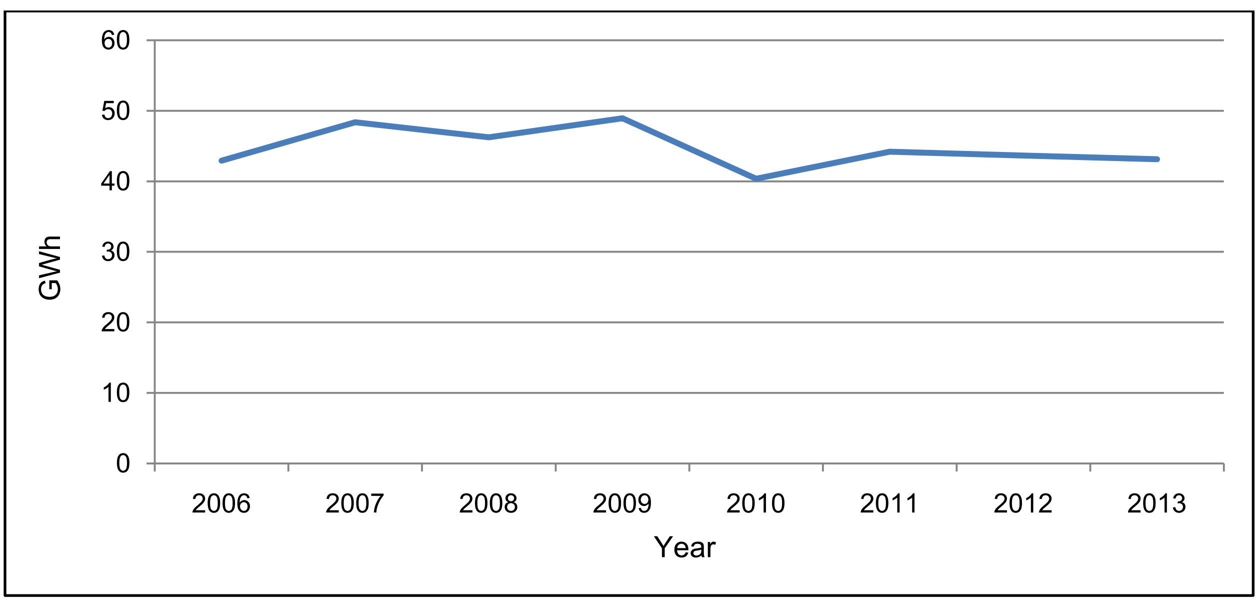
Figure 3.4.5 - Actual and Forecast Lighting Energy Consumption



3.4.6 Irrigation

Due to differences in acreage, crop types and energy use patterns and the complexity of economic and environmental issues affecting irrigation customers, growth patterns for energy sales in this class are variable. The before-DSM forecast is based on a five year average of the 2006 – 2010 period. The projected after-DSM irrigation load is 44 GWh for 2011 and 2012 and 43 GWh for 2013; this is a 1.2 percent decrease from 2012 to 2013.

Figure 3.4.6 - Actual and Forecast Irrigation Energy Consumption



3.5 LOSSES

System losses consist of:

1. Losses in the transmission and distribution system;
2. Company use;
3. Losses due to wheeling through the BC Hydro system; and
4. Unaccounted-for energy (meter inaccuracies and theft)

Losses are calculated by using a two year rolling average. The actual gross loss rate for 2012 is the average of the 2009 rate of 9.23 percent and the 2010 rate of 8.42 percent, which is 8.82 percent. The loss rate for 2013 is further reduced to 8.76 percent due to the AMI-based loss reduction program.

3.6 PEAK DEMAND

Peak demand is affected by economic activity, the number of customers, UPC and temperature. The Peak demand forecast is calculated by escalating ten years of historical peak load data by the actual historical energy load growth rates and then averaging the output. More detail on peak calculations can be found in Appendix D. Winter peak is estimated to be 721 MW in 2012 and 731 MW in 2013 while summer peak is forecast to be 567 MW in 2012 and 575 MW in 2013.

Table 3A1 - Normalized Energy Sales Including DSM and Other Savings

	Normalized					Approved	Forecast		
Energy Sales (GWh)	2006	2007	2008	2009	2010	2011	2011	2012	2013
Residential	1,064	1,165	1,196	1,239	1,242	1,261	1,255	1,264	1,276
Commercial	616	650	661	675	660	671	685	696	709
Wholesale	980	879	909	909	897	940	918	926	935
Industrial	348	314	218	216	234	233	243	250	255
Lighting	13	13	13	13	14	12	14	14	14
Irrigation	43	48	46	49	40	45	44	44	43
Sales	3,065	3,069	3,043	3,102	3,086	3,162	3,159	3,193	3,233
Losses	364	346	313	321	280	310	306	309	310
Gross Load	3,428	3,415	3,357	3,423	3,366	3,472	3,465	3,502	3,543
System Peak									
Winter Peak (MW)	672	648	672	661	661	723	710	721	731
Summer Peak (MW)	517	528	510	521	577	578	560	567	575

Note: Only Residential and Wholesale loads are normalized.

Table 3A2 - Actual Energy Sales Including DSM and Other Savings

						Approved	Forecast		
Energy Sales (GWh)	2006	2007	2008	2009	2010	2011	2011	2012	2013
Sales	3,041	3,064	3,087	3,157	3,044	3,162	3,159	3,193	3,233
Losses	364	346	313	321	280	310	306	309	310
Gross Load	3,405	3,410	3,400	3,478	3,324	3,472	3,465	3,502	3,543
Loss Percentage	10.68%	10.14%	9.21%	9.23%	8.42%	8.94%	8.82%	8.82%	8.76%

Table 3B - Annual Change by Customer Class

Change (%)	2006	2007	Normalized 2008	2009	2010	Approved 2011	2011	Forecast 2012	2013
Residential		9.5%	2.6%	3.6%	0.2%	1.6%	1.0%	0.7%	1.0%
Commercial		5.4%	1.7%	2.2%	-2.3%	1.7%	3.9%	1.6%	1.8%
Wholesale		-10.3%	3.4%	0.0%	-1.4%	4.9%	2.4%	0.8%	1.0%
Industrial		-9.8%	-30.6%	-1.0%	8.3%	-0.3%	3.8%	3.0%	2.1%
Lighting		1.9%	4.5%	-0.8%	8.9%	-18.2%	-1.8%	-1.8%	-2.0%
Irrigation		12.7%	-4.4%	5.9%	-17.5%	10.7%	9.5%	-1.2%	-1.2%
Net Load		0.2%	-0.8%	1.9%	-0.5%	2.4%	2.4%	1.1%	1.3%
Gross Load		-0.4%	-1.7%	2.0%	-1.7%	3.2%	2.9%	1.1%	1.2%
System Peak									
Winter Peak (MW)		-3.7%	3.8%	-1.6%	-0.1%	9.4%	7.5%	1.5%	1.5%
Summer Peak (MW)		2.2%	-3.5%	2.1%	10.7%	0.2%	-2.9%	1.3%	1.4%

Table 3C - Actual and Forecast Year-End Customer Count

	Actual					Approved	Forecast		
	2006	2007	2008	2009	2010	2011	2011	2012	2013
Residential	89,181	93,647	95,502	96,565	97,883	99,663	99,457	101,320	103,279
Commercial	10,285	11,010	11,216	11,308	11,419	11,714	11,572	11,837	12,130
Wholesale	8	7	7	7	7	7	7	7	7
Industrial	37	38	36	33	36	35	36	36	36
Lighting	1,905	1,992	1,910	1,874	1,830	1,836	1,830	1,830	1,830
Irrigation	997	1,030	1,048	1,066	1,075	1,081	1,075	1,075	1,075
Total Direct	102,413	107,724	109,719	110,853	112,250	114,336	113,977	116,105	118,357

Annual Change by Customer Class

	Actual					Approved	Forecast		
Change (%)	2006	2007	2008	2009	2010	2011	2011	2012	2013
Residential		5.0%	2.0%	1.1%	1.4%	1.8%	1.6%	1.9%	1.9%
Commercial		7.0%	1.9%	0.8%	1.0%	2.6%	1.3%	2.3%	2.5%
Wholesale		-12.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial		2.7%	-5.3%	-8.3%	6.1%	0.0%	2.9%	0.0%	0.0%
Lighting		4.6%	-4.1%	-1.9%	-2.3%	0.3%	0.0%	0.0%	0.0%
Irrigation		3.3%	1.7%	1.7%	0.8%	0.6%	0.0%	0.0%	0.0%
Total Direct		5.2%	1.9%	1.0%	1.3%	1.9%	1.5%	1.9%	1.9%

Appendix 3A

LONG TERM FORECASTS

Table A-1 - Long Term Forecast Energy Before DSM (GWh)

Year	Residential	Commercial	Wholesale	Industrial	Lighting	Irrigation	Net	Loss	Gross	Growth Rate (%)
2011	1,260	689	923	244	15	45	3,175	307	3,483	3.3%
2012	1,282	708	939	253	15	45	3,241	314	3,555	2.1%
2013	1,306	728	956	261	15	45	3,312	321	3,632	2.2%
2014	1,332	746	972	266	16	45	3,377	327	3,703	2.0%
2015	1,359	763	986	269	16	45	3,436	333	3,769	1.8%
2016	1,385	776	998	259	17	45	3,479	337	3,816	1.2%
2017	1,411	790	1,009	251	17	45	3,522	341	3,863	1.2%
2018	1,437	804	1,021	246	18	45	3,570	346	3,916	1.4%
2019	1,462	817	1,033	243	18	45	3,617	350	3,967	1.3%
2020	1,488	829	1,043	243	18	45	3,665	355	4,020	1.3%
2021	1,513	841	1,054	244	19	45	3,715	360	4,075	1.4%
2022	1,538	854	1,064	246	19	45	3,766	364	4,130	1.4%
2023	1,564	865	1,074	248	20	45	3,814	369	4,184	1.3%
2024	1,589	877	1,085	250	20	45	3,865	374	4,239	1.3%
2025	1,614	890	1,095	252	21	45	3,916	379	4,295	1.3%
2026	1,639	902	1,106	254	21	45	3,966	384	4,350	1.3%
2027	1,664	915	1,117	256	21	45	4,018	389	4,406	1.3%
2028	1,688	928	1,128	259	22	45	4,068	394	4,462	1.3%
2029	1,713	941	1,139	261	22	45	4,120	399	4,519	1.3%
2030	1,737	954	1,151	263	23	45	4,172	404	4,576	1.3%
2031	1,760	965	1,160	266	23	45	4,219	408	4,628	1.1%
2032	1,784	978	1,171	268	23	45	4,269	413	4,682	1.2%
2033	1,808	990	1,182	271	24	45	4,319	418	4,737	1.2%
2034	1,831	1,003	1,192	273	24	45	4,368	423	4,791	1.1%
2035	1,854	1,015	1,203	276	25	45	4,418	428	4,845	1.1%
2036	1,877	1,028	1,214	278	25	45	4,467	432	4,899	1.1%
2037	1,900	1,040	1,225	281	26	45	4,516	437	4,953	1.1%
2038	1,923	1,053	1,235	283	26	45	4,565	442	5,007	1.1%
2039	1,946	1,065	1,246	286	26	45	4,614	447	5,060	1.1%
2040	1,968	1,078	1,257	288	27	45	4,662	451	5,114	1.1%

Note: This forecast does not include incremental DSM after 2010 and other savings.

Table A-2 - Long Term Forecast Energy After DSM (GWh)

Year	Residential	Commercial	Wholesale	Industrial	Lighting	Irrigation	Net	Loss	Gross	Growth Rate (%)
2010	1,242	660	897	234	14	40	3,086	284	3,370	-1.5%
2011	1,255	685	918	243	14	44	3,159	306	3,465	2.8%
2012	1,264	696	926	250	14	44	3,193	309	3,502	1.1%
2013	1,276	709	935	255	14	43	3,233	310	3,543	1.2%
2014	1,290	719	943	258	13	43	3,266	311	3,577	0.9%
2015	1,301	727	948	258	13	42	3,289	310	3,599	0.6%
2016	1,312	732	951	245	13	41	3,293	308	3,601	0.1%
2017	1,328	737	954	235	13	41	3,307	307	3,614	0.4%
2018	1,343	744	959	228	13	40	3,328	309	3,637	0.6%
2019	1,357	751	963	223	14	40	3,347	310	3,658	0.6%
2020	1,372	755	966	220	14	39	3,367	312	3,679	0.6%
2021	1,386	761	970	219	15	39	3,390	315	3,704	0.7%
2022	1,400	766	973	219	15	38	3,412	317	3,729	0.7%
2023	1,416	771	976	219	16	38	3,435	319	3,754	0.7%
2024	1,433	776	979	219	16	37	3,460	321	3,781	0.7%
2025	1,449	781	983	219	16	37	3,486	323	3,809	0.7%
2026	1,466	787	986	219	17	36	3,511	325	3,836	0.7%
2027	1,482	793	990	219	17	36	3,536	328	3,864	0.7%
2028	1,497	798	994	219	18	35	3,562	330	3,892	0.7%
2029	1,513	805	998	219	18	35	3,589	332	3,921	0.7%
2030	1,528	811	1,003	220	19	34	3,615	335	3,949	0.7%
2031	1,543	815	1,005	220	19	34	3,637	337	3,973	0.6%
2032	1,559	821	1,009	220	19	33	3,661	339	4,000	0.7%
2033	1,573	827	1,012	221	20	33	3,685	341	4,026	0.7%
2034	1,588	832	1,016	221	20	32	3,710	343	4,053	0.7%
2035	1,603	838	1,019	221	21	32	3,734	345	4,079	0.6%
2036	1,617	843	1,023	222	21	31	3,757	347	4,105	0.6%
2037	1,631	849	1,027	222	22	31	3,781	349	4,130	0.6%
2038	1,645	854	1,030	222	22	30	3,805	351	4,156	0.6%
2039	1,659	860	1,034	223	22	30	3,828	353	4,182	0.6%
2040	1,673	865	1,037	223	23	29	3,851	356	4,207	0.6%

Note: This forecast does include incremental DSM after 2010 and other savings.

Table A-3 - Long Term Peak Forecast Before DSM (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
2010	661	577	519	474	425	472	577	569	414	481	611	661	661	577
2011	664	607	565	492	455	499	556	539	448	523	610	677	715	563
2012	677	620	577	502	464	509	568	550	457	533	622	691	730	575
2013	692	633	589	512	474	520	580	562	467	545	636	706	745	587
2014	705	645	600	522	483	530	591	573	476	555	648	719	758	598
2015	718	657	611	531	491	539	601	583	484	565	659	732	770	609
2016	726	665	618	538	498	546	609	590	490	572	667	741	780	616
2017	735	673	626	544	504	553	616	597	496	579	675	750	789	624
2018	745	682	634	552	510	560	625	605	502	587	685	760	800	632
2019	755	691	643	559	517	567	633	613	509	594	694	770	810	640
2020	765	700	651	566	524	575	641	621	515	602	703	780	821	649
2021	775	709	660	574	531	583	650	630	522	610	712	791	832	657
2022	786	719	669	581	538	590	658	638	529	618	722	801	843	666
2023	796	728	677	589	545	598	667	646	536	626	731	811	854	675
2024	806	738	686	597	552	606	676	655	543	634	741	822	865	684
2025	817	747	695	604	559	614	684	663	550	643	750	833	877	692
2026	827	757	704	612	566	621	693	672	557	651	760	843	888	701
2027	838	766	713	620	573	629	702	680	564	659	769	854	899	710
2028	848	776	722	628	580	637	711	689	571	667	779	865	910	719
2029	859	786	731	635	588	645	720	697	579	676	789	876	922	728
2030	870	796	740	643	595	653	729	706	586	684	799	887	933	737
2031	879	805	748	651	602	661	737	714	592	692	808	897	944	745
2032	890	814	757	658	609	668	745	722	599	700	817	907	955	754
2033	900	823	766	666	616	676	754	731	606	708	827	918	965	763
2034	910	833	774	673	623	684	762	739	613	716	836	928	976	772
2035	920	842	783	681	630	691	771	747	620	724	845	939	987	780
2036	931	851	792	688	637	699	779	755	627	732	855	949	998	789
2037	941	861	800	696	643	706	788	764	633	740	864	959	1009	797
2038	951	870	809	703	650	714	796	772	640	748	873	970	1020	806
2039	961	879	817	711	657	722	805	780	647	756	882	980	1030	814
2040	971	888	826	718	664	729	813	788	654	764	892	990	1041	823

Note: This forecast does not include incremental DSM after 2010 and other savings.

Table A-4 - Long Term Peak Forecast After DSM (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
2010	661	577	519	474	425	472	577	569	414	481	611	661	661	577
2011	663	607	564	490	453	497	554	536	444	519	606	672	710	560
2012	673	614	571	496	458	503	561	543	449	525	614	682	721	567
2013	683	623	579	502	464	509	569	550	454	532	623	692	731	575
2014	692	630	587	508	469	515	575	556	458	538	630	701	741	582
2015	699	637	593	512	473	519	581	561	461	543	636	709	747	588
2016	703	639	595	514	474	521	583	563	462	545	639	713	751	590
2017	707	642	598	516	476	523	586	566	464	548	643	718	758	593
2018	713	647	603	519	479	527	591	570	466	552	649	724	764	598
2019	719	652	608	523	482	530	595	574	469	556	654	730	771	603
2020	725	657	613	526	486	534	599	578	472	559	659	737	778	607
2021	732	662	618	530	489	538	604	582	475	564	665	743	785	612
2022	739	668	623	534	493	542	609	587	478	568	670	750	792	617
2023	745	673	628	538	496	546	614	591	480	572	676	757	799	622
2024	752	678	633	542	500	550	619	595	484	577	681	764	807	627
2025	758	684	639	546	503	554	624	600	487	581	687	770	814	632
2026	765	689	644	550	507	558	629	604	490	585	693	777	821	637
2027	772	695	649	554	510	562	634	609	493	590	699	784	829	642
2028	778	700	655	558	514	566	639	614	496	594	704	791	836	647
2029	785	706	660	562	518	570	644	618	499	599	710	798	844	652
2030	792	711	665	567	522	574	649	623	502	604	716	805	851	658
2031	798	716	670	570	525	578	653	627	505	607	721	811	858	662
2032	805	721	675	574	528	582	658	631	508	612	727	818	865	667
2033	811	727	680	578	532	586	663	636	511	616	733	825	872	672
2034	817	732	685	582	535	590	668	640	514	620	738	831	879	677
2035	824	737	690	585	538	593	672	644	516	624	744	838	887	681
2036	830	742	695	589	542	597	677	649	519	629	749	844	894	686
2037	837	747	700	593	545	601	682	653	522	633	754	851	901	691
2038	843	753	705	597	549	605	686	657	525	637	760	857	908	696
2039	849	758	710	600	552	609	691	661	528	641	765	864	914	700
2040	855	763	715	604	555	612	695	665	531	645	771	870	921	705

Note: This forecast does include incremental DSM after 2010 and other savings.

Appendix 3B

WEATHER NORMALIZATION

B. WEATHER NORMALIZATION

Electricity consumption is impacted by weather, particularly by temperature. For example, energy requirements in an extremely cold winter month can be significantly higher than requirements in a normal weather condition. In order to analyze the load behaviour, for example an increasing trend in the residential sector because of an increasing number of customer counts, and to forecast loads under an assumption of normal weather, it is necessary to remove those extreme weather effects. This is the first step in forecasting.

Currently, only the Residential and Wholesale load classes are normalized. Weather normalization of the Commercial and Irrigation classes was also investigated but results were not statically reliable (values of the coefficient of determination or R^2 of regression analysis were low). Industrial and street lighting loads are typically insensitive to the temperature.

Steps for weather (temperature) normalization are described as follows:

1. Calculate monthly heating degree days (HDD)[1] and cooling degree days (CDD)[2] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages (2000-2009) for each month of the year. These are used as the parameters of normal weather.
3. For the each of the residential and wholesale classes, regress energy on HDD or CDD on a seasonal basis. Four seasons were defined: winter is November to February, spring is March to May, fall is September to October, and summer is June to August. Thus all monthly energy and degree day data for each season are used and four separate regressions were calculated for each class. Dummy variables were included in the regressions to recognize that in 2007 Princeton Light and Power Inc. (PLP) ceased to exist as a wholesale customer and its customers became directly served by FortisBC.

[1] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.

[2] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

Chow tests confirmed that energy use consumption in the different seasons responded differently to HDD and CDD (regression coefficients were statistically different).

4. To normalize a month, e.g. February 2011:
   a) obtain the month's HDD (or CDD) information from the Environment Canada;
   b) calculate the deviation from the 10-year average HDD (CDD) as found in Step 2;
   c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder;
   d) add the normalization adder to the month's load (residential or wholesale).

The general equation to normalize energy requirements in month t is shown below.

Normalized energy_t = Energy_t –HDD slope_t*(HDD_t – Normal HDD_t) for t = 1-5, 9-12

Normalized energy_t = Energy_t –CDD slope_t*(CDD_t – Normal CDD_t) for t = 6, 7, 8

Regression slopes (MWh/degree day) and 10-year average degree days are found in the following table.

Table B-1 - Weather Normalization Coefficients and Normal Weather

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential HDD	157	157	93	93	93	-	-	-	50	50	157	157
Residential CDD	-	-	-	-	-	57	57	57	-	-	-	-
Wholesale HDD	86	86	56	56	56	-	-	-	30	30	86	86
Wholesale CDD	-	-	-	-	-	69	69	69	-	-	-	-
Normal HDD	576	485	410	271	133	41	5	10	90	287	439	579
Normal CDD	0	0	0	0	8	38	127	91	9	0	0	0

As shown in the table above, an additional HDD in February causes energy use to rise by 157 MWh for the residential sector, while an extra HDD in May causes consumption to rise by only 93 MWh.

In previous years, the Company used a single pair of regression coefficients for HDD and CDD in all months, which were obtained by regressing all monthly load data on all monthly HDD and CDD data. However, statistical tests showed that different seasons have different regression coefficients (i.e. that the load's sensitivity to temperature is different in different seasons). Therefore, the Company renormalized prior year data as part of the 2012-2013 load forecast.

Appendix 3C

ENERGY FORECAST

C. ENERGY FORECAST

C.1 Residential

The formula to forecast the before-DSM residential load in year *t*, is

Before DSM $Load_t$ = UPC_t*Average Customer $Count_t$, where

- UPC is assumed to stay at a constant value of 12.77 MWh per customer per year;
- Average Customer $Count_t$ = 0.5*(Year-end $Count_t$ + Year-end Countt-1)
- Year-end Count is forecast as a sum of the preceding year-end count and a forecast growth

Year-end $Count_t$ = Year-end $Count_{t-1}$ + Year-end Count $Growth_t$

The customer count growth is based on the provincial housing starts data supplied by the CBOC according to the regression model below:

Year-end Customer $Growth_t$ = b_0 + b_1*Housing $Starts_t$

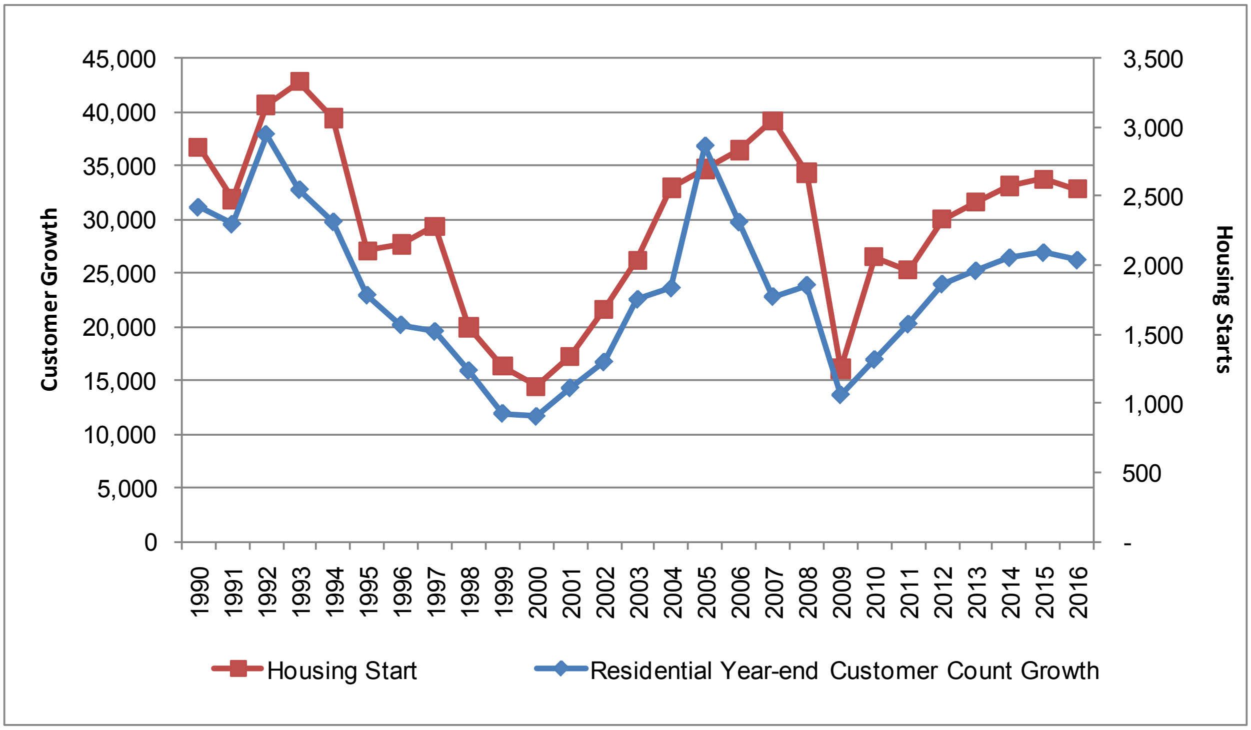
Regression results of the year-end residential customer count on 1990-2009 housing starts data are found in the following table. One provincial housing start adds 0.0612 customers. Note that the customer growth in 2007 was pre-processed to remove transferred residential customers from PLP.

Table C.1-1 - Regression Results on Housing Starts Data

Number of Data	20	P-value
Intercept b0	25.62	0.9111
Housing Starts	0.0612	0.0000
R-sq	0.79	
F significance	0.000	
Durbin-Watson	1.78	Passed
No Autocorrelation	[1.41,2.59]	

Figure C.1-1 shows that the housing starts series keeps track of the residential customer count growth quite well, except for the 2006-2007 period when housing speculation took place. FortisBC believes that any such speculation will be shortly corrected by the market.

Figure C.1-1 - Residential Customer Count Growth vs. Housing Starts



The load after DSM and other savings is calculated as

$$\text{After DSM Load}_t = \text{Before DSM Load}_t - \text{DSM}_t - \text{Other}_t$$

DSM savings are incremental (after 2010).

Other adjustments include savings from the RIB rate beginning in 2012, the Customer Information Portal (CIP) beginning in 2015, and the AMI-based revenue protection programs starting in 2013. A sale increase by the AMI-based revenue protection programs will be offset by a reduction in losses so that the total impact of the AMI-based programs on the gross load is zero

Table C.1-2 - Residential Energy Savings Before Losses - GWh

Year	DSM	RIB	CIP	AMI RP
2011	5	-	-	-
2012	15	3	-	-
2013	24	8	-	(2)

C.2 Commercial

The Commercial load in year *t* is forecast based on provincial GDP, which is supplied by CBOC. The relationship is estimated from the following equations.

$$\text{After DSM Load}_t = \text{Before DSM Load}_t - \text{DSM}_t$$

$$\text{Before DSM Load}_t = b_0 + b_1{*}\text{GDP}_t + b_2{*}\text{Dummy}_t$$

where

- Dummy_t is a binary variable for PLP
- Coefficients b_0, b1, and b_2 are obtained from an OLS regression analysis on the 2000 to 2009 data

Table C.2-1 - Commercial Load on GDP

Number of Data	10	P-value
Intercept b0	70,956	0.4858
GDP b1	3.93	0.0005
Dummy b2	-48,603	0.0169
Adjusted R-sq	0.95	
F significance	0.0000	
Durbin-Watson	1.85	Passed
No Autocorrelation	[1.64, 2.36]	

C.3 Wholesale

The wholesale load in year *t* is also forecast on provincial GDP and the relationship is estimated from the following equations.

$$\text{After DSM Load}_t = \text{Before DSM Load}_t - \text{DSM}_t$$

$$\text{Before DSM Load}_t = b_0 + b_1{*}\text{GDP}_t$$

where

- Coefficients b_0 and b1 are obtained from an OLS regression analysis on the 2000 to 2009 data.

For this class, a dummy variable for the 2007 event does not need to be included as PLP's loads prior to 2007 can be removed from the historical wholesale loads in a pre-processing step.

Table C.3-1 - Wholesale Load on GDP

Number of Data	10	P-value
Intercept b0	390,375	0.000
GDP b1	3.39	0.000
R-sq	0.90	
F significance	0.00	
Durbin-Watson	2.29	Passed
No Autocorrelation	[1.32, 2.68]	

C.4 Industrial

For the 2011-2016 period, the before DSM industrial load in year *t* is the sum of 36 individual customers. For each customer in each year, the customer-supplied forecast is used if available; otherwise the customer's 2010 load is escalated by its industrial sector's forecast of the GDP growth rate, which is provided by CBOC. After 2016, the whole class' load in a year is escalated by the year's composite GDP growth rate, which is a load weighted average of GDP growth rates of the industrial sectors that the customers are in.

$$\text{After DSM Load}_t = \text{Before DSM Load}_t - \text{DSM}_t$$

C.5 Lighting

Street lighting forecast is based on a trend analysis on the 2006-2010 data. Earlier data is not used because numbers in the database appear to be inconsistent in some months. Forecasts for year *t* are

$$\text{After DSM Load}_t = \text{Before DSM Load}_t - \text{DSM}_t$$

$$\text{Before DSM Load}_t = b_0 + b_1 {*} t$$

Regression outputs are summarized below.

Table C.5-1 - Street lighting Load on Year

Number of Data	5	P-value
Intercept b0	-838,185	0.028
Year b1	424.06	0.026
R-sq	0.85	
F significance	0.03	

C.6 Irrigation

The before DSM irrigation load is a simple average of actual loads in 2006-2010.

$$\text{After DSM Load}_t = \text{Before DSM Load}_t - \text{DSM}_t$$

C.7 DSM

Total DSM is forecast to be 50 GWh in 2012 and 80 GWh in 2013. DSM by class is shown in the table below.

Table C.7-1 - DSM for Each Class (GWh)

	2012	2013
Residential	15	24
Commercial	12	19
Industrial	4	6
Wholesale	13	21
Lighting	1	2
Irrigation	1	1
Losses	4	7
Total DSM	50	80

Appendix 3D

PEAK DEMAND FORECAST

D. PEAK DEMAND FORECAST

D.1 Expected Peak

Historical monthly peak load data for ten years (2000-2009) are escalated by historical load growth rates and then averaged to obtain monthly peaks under normal weather conditions. Celgar loads are excluded from the historical data. Seasonal peaks are used for both the winter and the summer. The twelve monthly peaks, as well as the seasonal peaks, are then escalated by the energy load growth rate in 2010 and annual load growth rates in the forecast period to produce forecast monthly peaks. Celgar's expected monthly peak of 8 MW is then added to these values. The winter peak and the summer peak are assumed to replace monthly peaks in December and July respectively.

The after-DSM peak forecast is found by subtracting the DSM capacity saving forecast from the before-DSM peak forecast for each month in each year.

Appendix 3E

HIGH – LOW LOAD FORECAST
WITH MONTE CARLO SIMULATION

E. HIGH – LOW LOAD FORECAST WITH MONTE CARLO SIMULATION

This description is included for completeness and does not impact revenue requirements. The main body of the report describes the load forecast in the expected case, which is called the Reference forecast. It is known that there is uncertainty involved in any forecast, and for planning purposes, a low-high range load forecast around the Reference forecast is very useful. A typical low-high range is P10 and P90 where:

- P10 means there is a 10 percent probability that the load will be less than this value in a particular year; and
- P90 means there is a 90 percent probability that the load will be less than this value in a particular year.

As there are many interacting random factors that may influence the load forecast and contribute to uncertainty, a popular method to obtain such a range forecast is Monte Carlo (MC) simulation. Because the load forecasting model is Excel based, FortisBC uses MC add-in software called @RISK from Palisade Co. Since DSM is integrated into the load forecasting model, FortisBC is able to find both before-DSM and after-DSM load forecasts as direct outputs from the MC simulation.

There are three steps in developing low-high range forecasts for energy requirements and peak demand:

1. Identify influencing factors;
2. Assign a probability distribution to each of the influencing factors found in step 1;
3. Apply repeated random sampling with the influencing factors found above as random input variables and aggregate outputs to reach annual low-high range forecasts.

Random variables as influencing factors for the before DSM forecasts and their probability distribution are indentified for each load class as follows.

- *Residential*: Housing starts as a load driver for the residential class. UPC is still considered a constant as a result of various factors offsetting one another. The housing starts as a random variable in year *t* is

$$\text{Housing Starts}_t = \text{Housing Starts}_{t-1} + \text{Housing Starts Growth}_t$$

where Housing Starts $Growth_t$ is a normally distributed random variable with mean equal to the corresponding growth in the Reference case and standard deviation equal to that computed from the historical growths in 1990-2009.

- *Commercial*: GDP is the load driver for this load class. Similarly to housing starts, random variable GDP in year *t* is

$$GDP_t = GDP_{t-1} + GDP\ Growth_t$$

where GDP $Growth_t$ is a normally distributed random variable with mean equal to the corresponding growth in the Reference case and standard deviation equal to the that computed from the growths in 1990-2009.

- *Wholesale*: GDP as a load driver for this load class;
- *Industrial*: A majority of load forecast in the 2011-2016 were supplied by industrial customers. Because FortisBC does not have specific risk assessments for each of them, forecasts in this period are considered certain. From 2017 onwards, the energy requirement in year *t* is a random variable

$$Load_t = Load_{t-1} + Load\ Growth_t$$

where Load $Growth_t$ is a normally distributed random variable with mean equal to the corresponding load growth in the Reference case and standard deviation equal to the one computed from the industrial load growths in 2001-2010, excluding a severe drop in 2008 due to recession, which is considered as an outlier.

- *Lighting*: No uncertainty is assumed for this class as its impact will be negligible given the size of this load class.
- *Irrigation*: The load in year *t* is a random variable

$$Load_t = Constant + Load\ Growth_t$$

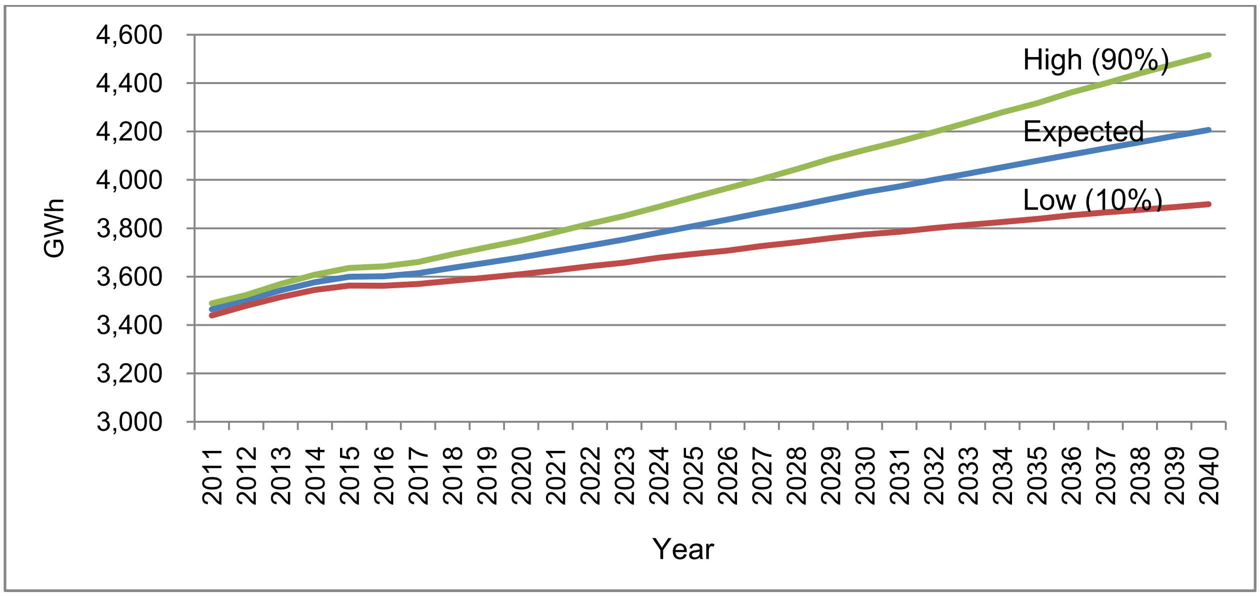
where Constant is the 5-year average of loads in 2006-2010 and Load Growth is a normally distributed random variable with mean 0 and standard deviation equal to the one computed from the irrigation load growths in 2001-2010.

The after-DSM (load forecasts with incremental DSM and other RIB and AMI based adjustments) are also impacted by the random variables identified above. In addition, there is also significant uncertainty in the DSM performance. Based on the 1991-2010 data, DSM performance is modeled as a normally distributed random variable with mean 100 percent and standard deviation 21.73 percent. Therefore, if an incremental DSM target for a year is 50 percent of the year's load growth, then for 95 percent of the time, DSM performance will be in the range (28.27%, 71,73%), where 28.27% = 50%*(100% - 2*21.73%) and 71.73% = 50%*(100% + 2*21.73%).

The after DSM load range forecast is obtained as a direct output from a MC simulation in which both load and DSM vary.

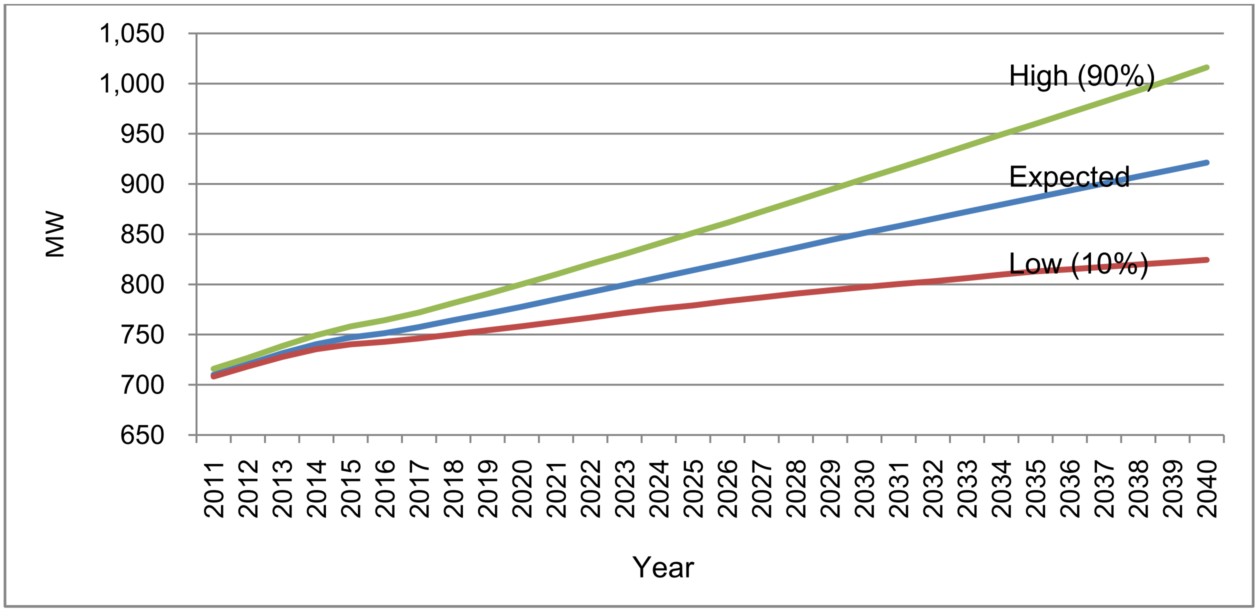
Before and after DSM range forecasts for energy requirements and peak demand are displayed in graphs below.

Figure E-1 - After DSM Gross Energy



Note: This forecast does include incremental DSM after 2010 and other savings.

Figure E-2 - After DSM Peak Demand



Note: This forecast does include incremental DSM after 2010 and other savings.

Appendix 3F

SYSTEM PLANNING FORECASTS

F. SYSTEM PLANNING FORECAST

The size and timing of capital-intensive investments in generators, transmission lines, substations and distribution lines are driven by customer demand for electricity and have direct and considerable implications on customer service reliability, capital requirements and customer rates. The accurate forecasting of electricity demand, therefore, is important in electric utility planning and is the starting point in the development of future generation, transmission and distribution facilities. Substantial deviations of the actual demand from forecast demand will result in either overbuilding of supply facilities or curtailment of customer demand.

FortisBC develops two separate load forecasts annually. The resource planning forecast is a "top down" total system load forecast, the second forecast is a "per substation" load forecast that is produced from the "bottom up" (i.e. from the distribution feeder level). This forecast is the basis for the development of capital plans for distribution substation and feeder reinforcements.

The two forecasts are fundamentally different and are developed using different methodologies and used for different reasons. The resource planning forecast is a "weather normalized" forecast used to determine FortisBC's resource requirements on a monthly and annual basis and does not incorporate potential weather extremes. On the other hand, the substation load forecast attempts to account for expected weather extremes which directly impact winter and summer peak loads. It is a non-coincidental peak load forecast used to determine how much substation, distribution and transmission infrastructure will be needed in order to supply all FortisBC customers during peak demand periods and adverse weather conditions.

F.1 Distribution Feeder Forecast

Load forecasts are developed at the distribution feeder level, and are then built up to the transformer level using historical coincident factors. In the past, the forecasts were based on linear projections of recent load growth. With the 2010-11 load forecast the forecasting method was refined to incorporate regional and feeder load growth rates that are compatible with the system load growth determined in the resource planning forecast described above. Where appropriate, the Distribution Load Forecast is adjusted to reflect information available through the relevant official community plans and through ongoing discussions with regional or municipal planners and local developers.

The feeder level forecast includes historical loading, growth trends, the addition of known large developments and load transfers between feeders. Two system elements, Hollywood Feeder 1, and Hollywood transformer T3, are used as an example. The "Year 0" feeder forecast methodology is illustrated in Figure F.1-1. It is based on the previous five year peaks, using the highest peak as a starting point, in order to capture extreme weather impacts on load.

The "Year 0" feeder forecast is calculated as follows:

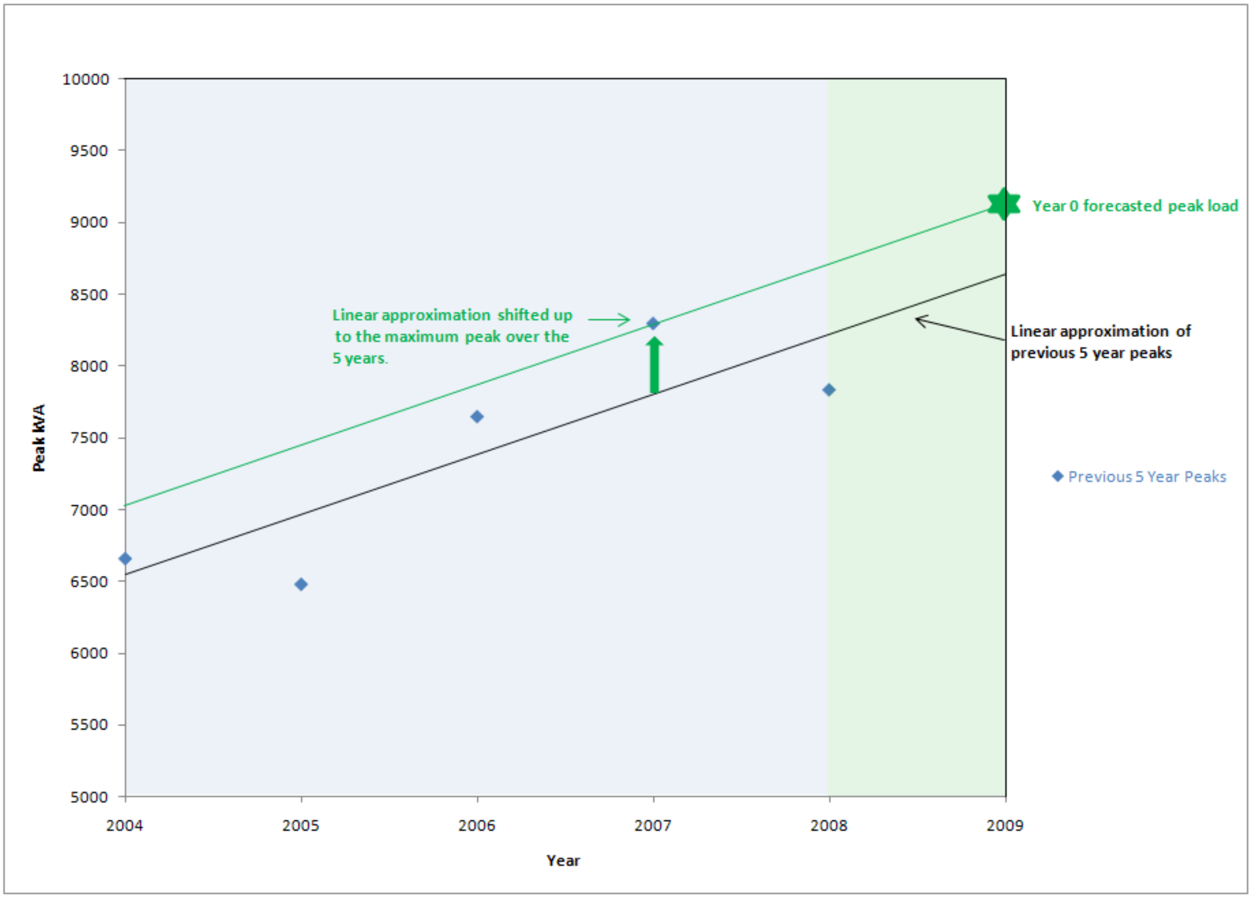
Feeder Peak (Year 0) = (5 year historical max peak load)
+ (5 year annual historical growth)
± (highly probable load developments and known feeder switching)

Feeder forecasts for years 1-20 are calculated as follows:

Feeder Peak = (Year 0 peak) x (forecast regional load growth rate)
± (highly probable load developments and known feeder switching)

The forecast regional load growth rate is determined from trends of historical regional load data, adjusted to the resource planning forecast growth rate. Highly probable load developments are community developments that have an expected online date and defined load. Feeder switching loads are those loads that are expected to transfer from one facility to another to off-load a feeder or transformer in a certain year.

Figure F.1-1 - Determination of "Year 0" Peak Load



F.2 Distribution Substation Transformer Load Forecast

The transformer level forecast includes both the feeder peak loading and the diversity factor information. Each year of the transformer forecast is calculated as follows:

Transformer Peak (Year 0-20) = Σ (connected feeder peaks)*(transformer diversity factor)

The diversity factor is the transformer peak divided by the sum of the connected feeder peaks. This diversity factor calculation is applied to five years of historical data. The forecast diversity factors are based on an average of the past five diversity factors. The diversity factor is calculated as follows:

Historical Diversity Factor = (transformer peak) / Σ(feeder peaks)

Forecast Diversity Factor = Σ(past 5 year diversity factors) / (5)

Summations of the appropriate transformer forecast loads are applied to develop substation load forecasts for summer and winter.

F.3 Transmission Planning Forecast

The transmission planning group derives data from both the resource planning forecast and the Distribution Load Forecasts to develop forecast loads allocated to FortisBC busses on the Western Electricity Coordinating Council (WECC) power flow model. This data is submitted to the WECC annually for application in regional and system-wide transmission planning studies.

In planning the bulk transmission system, FortisBC uses a load forecast with DSM impacts included. DSM resources have a more predictable impact at the bulk transmission level than at any local area level, due to (1) regional load diversity and (2) difficulties in allocating DSM deliveries to local circuits and distribution feeders. In local area transmission and distribution planning studies, a load forecast without DSM impacts is used and, when project timelines are deemed to be impacted, DSM considerations are included in a sensitivity study to determine potential impacts on T&D projects. As more information is gathered on allocations of DSM resources to local area networks, DSM will be included in local area transmission and distribution studies.

F.4 1-in-20 Peak Forecast

For Distribution and Transmission planning purposes, a one year in twenty forecast is required and such forecast was developed by Resource Planning at the request of the System Planning group. This ”1-in-20” forecast estimates the peak demand that would be reached once in every twenty years; therefore the peak demand is expected to be lower than the 1-in-20 forecast 95 percent of the time. This provides a peak forecast for transmission planning studies that has a quantitative risk index, as is necessary to achieve consistency with industry practice and established reliability standards.

The 1-in-20 load forecast is developed in a series of steps:

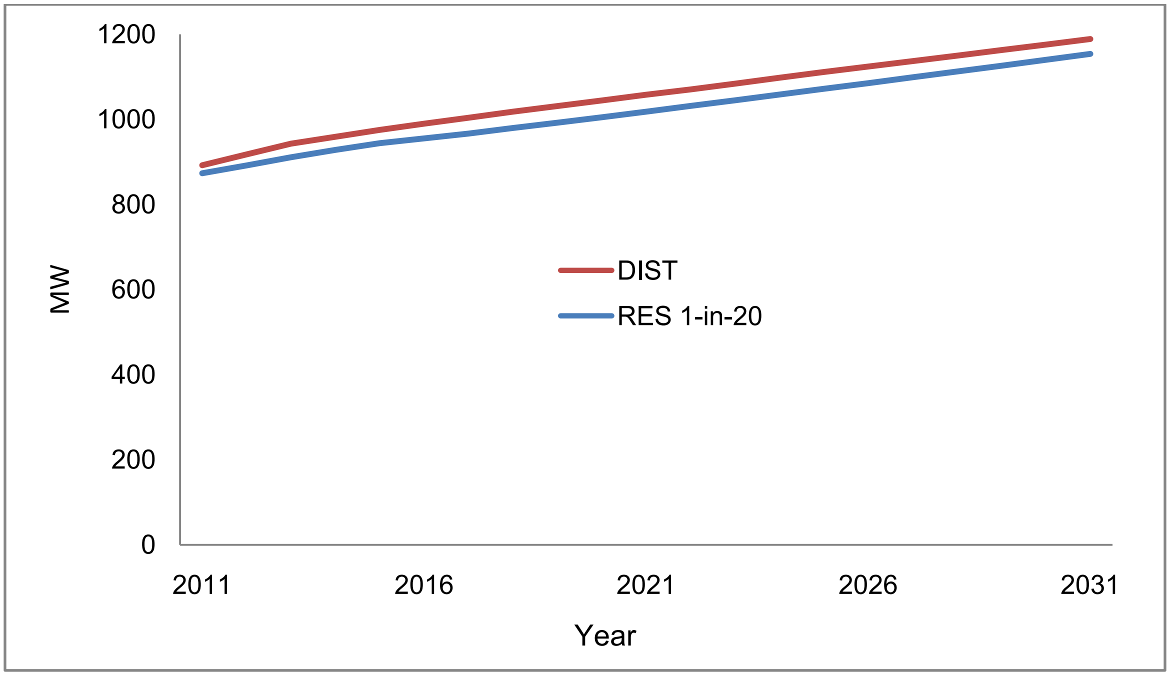
- The hour for each peak (excluding Celgar and wheeling losses) in January, February, November, December, as well as June, July and August for each year in the period 1990-2010 is recorded.
- Historical net energy growth rates are derived from actual 1990-2009 sales. Forecast net energy growth rates are used to escalate the peaks into future years as described below.

- Assuming that the weather in 2011 will be similar to the weather of base year 1990, the corresponding January peak in 2011 is obtained by applying to the base year the cumulative growth of years 1991-2011. The 2011 peaks for February, November, and December, as well as June, July, August are obtained in the same manner. The calculation is then repeated for the remaining 19 base years from 1991 to 2009.
- The method yields 20 values for the 2011 winter peaks corresponding to 20 base years from 1990 to 2009. The maximum peak of these 20 values is defined as the 1-in-20 winter peak for 2011. The 1-in-20 summer peak is derived in the same manner. The resulting 2011 peaks are then escalated with growth rates to compute the 1-in-20 forecast peaks over the planning horizon.

F.5 Comparison of Resource Planning and Distribution Load Forecasts

The two FortisBC load forecasts use different methodologies, serve different purposes and yet have an acceptable degree of consistency with one another. The graph of Figure F.4 shows the Resource Planning “1-in-20” and the Distribution Planning winter forecasts. For the purposes of this comparison some adjustments are made to allow comparability of the two forecasts: (1) the Celgar load is removed from the Distribution Planning forecast, as it is not included in the Resource Planning forecast, (2) the two forecasts are adjusted to the same level of transmission and distribution losses, (3) the BC Hydro load at Duck Lake is added in the Resource Planning forecast, as it has been included in the Distribution Planning forecast, (4) the Resource Planning forecast is increased by 8 percent throughout the time horizon to account for peak load diversity of 3 percent between system and regional totals and peak load diversity of 5 percent between regional totals and substation totals. The two forecasts show good consistency. The differences between the two forecasts is in the range 2 - 3 percent, which is acceptable considering the methodological differences between a “top down” and a “bottom up” load forecast.

Figure F.5-1 - Comparison of Resource Planning and Distribution Winter Load Forecasts



2012 – 2013 Revenue Requirements
(2012-13 RRA)

Tab 4
Cost of Service

June 30, 2011

FortisBC Inc.

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4.0 INTRODUCTION

FortisBC's cost of service is forecast to increase by approximately $15.7 million in 2012 and a further $24.6 million in 2013. The increased cost of service is necessary for the Company to continue to provide safe and reliable service to its customers. The increasing customer counts and electrical facilities outlined in Appendix G of the Application continue to put pressure on FortisBC's cost of providing services to its customers.

While the increased cost of service is attributable to a number of factors, there are three key underlying drivers: (1) increases in power purchase costs; (2) increases in utility rate base; (3) increases in the costs associated with financing that rate base including depreciation.

Each of these items is further discussed below.

4.1 POWER PURCHASE AND WHEELING

This section includes an estimate of 2011 Power Purchase Expense based on FortisBC's actual results to April 30, 2011, with an estimate for May through December, and a complete forecast of Power Purchase Expense for 2012 and 2013 (see Tables 4.1.4-2 and 4.1.4-3).

As shown in Table 4.1-1 below, Power Purchase Expense is forecast at $91.0 million for 2012 and $98.8 million for 2013, as compared to $76.0 million currently estimated for 2011. The increases in 2012 and 2013 are primarily due to an increase in forecast load, greater use of the BC Hydro Power Purchase Agreement (PPA), annual increases to the Brilliant and BC Hydro rates, and the inclusion of the management costs associated with power purchase costs (explained in section 4.1.2.6). Balancing Pool adjustments account for the difference between energy entitlements under the Canal Plant Agreement (CPA) and actual usage.

Table 4.1-1 Total Power Purchase Expense (2010-2013)

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Brilliant	33,216	32,267	35,601	36,785
2	BC Hydro	29,544	36,874	52,519	57,965
3	Independent Power Producers	914	153	155	158
4	Capacity Block Purchases	2,080	2,291	2,475	2,808
5	Market Purchases	8,222	4,211	214	545
6	Surplus Revenues	(1,000)	(259)	(284)	(267)
7	Capital Projects	(398)	(467)	-	-
8	Special and Accounting Adjustments	421	385	(750)	(750)
9	Balancing Pool	(1,036)	501	(156)	-
10	Planning Reserve Margin	-	-	-	311
11	Management Expense	-	-	1,211	1,266
12	TOTAL	71,964	75,956	90,984	98,821

4.1.1 Review of 2011

The winter of 2010-11 saw above-average snow packs and stronger than normal run-off in the first quarter. This early run-off combined with ongoing moderate natural gas prices and a growing base of variable and unpredictable wind generation in the Pacific Northwest provided significant opportunities to obtain market energy at rates below those of the BC Hydro PPA.

FortisBC annual gross load is forecast to be 29 GWh above approved 2011 (net of Demand Side Management (DSM) savings). Power purchase expense is expected to be $5.3 million below approved 2011 for the year, as shown in Table 4.1.1-1 below as a net result of:

a) Lower BC Hydro costs, net of accounting adjustments, of $9.9 million, due primarily to a reduced BC Hydro purchase volume as a result of increased market purchases at rates below the 3808 rate;

b) A combined increase of $3.8 million in market purchases and balancing pool usage; and

c) A $0.75 million reduction to Power Purchase Expense negotiated in the 2011 NSA.

The Company has included the interim BC Hydro rate increase of 8 percent on May 1, 2011, including the deferral account rate rider, as well as estimated BC Hydro rate increases of 8 percent on each of April 1, 2012 and April 1, 2013.

In 2011, there was normal annual generator maintenance on the FortisBC generating units. The Corra Linn Unit 1 Upgrade and Life Extension (ULE) project was completed in March 2011, which required a planned outage beginning in 2010. The ULE for Corra Linn Unit 2 is expected to begin in the summer of 2011 and should be completed by December 2011. The increased power purchase costs as a result of these projects are offset by charges to the capital cost of the project and therefore do not impact Power Purchase Expense (see Line 7 of Table 4.1.1-1). The Company forecasts receiving the increased entitlements under the CPA for these projects in 2011 and 2012 as detailed below.

Table 4.1.1-1 Total Power Purchase Expense (2011)

		Approved 2011	Forecast 2011	Difference
		($000s)		
1	Brilliant	32,282	32,267	(16)
2	BC Hydro	46,811	36,874	(9,937)
3	Independent Power Producers	168	153	(16)
4	Capacity Block Purchases	2,406	2,291	(115)
5	Market Purchases	856	4,211	3,356
6	Surplus Revenues	(670)	(259)	411
7	Capital Projects	(377)	(467)	(89)
8	Special and Accounting Adjustments	-	385	385
9	Balancing Pool	486	501	15
10	BCUC Negotiated Rate Reduction	(750)		750
11	**TOTAL**	81,212	75,956	(5,256)

4.1.2 Power Purchase

The goal of the Company's resource acquisition policy is to meet customer load requirements for the lowest reasonable cost with minimal environmental impacts. This goal is subject to ongoing resource uncertainties that are described in greater detail in the following section.

4.1.2.1 POWER PURCHASE/RESOURCE UNCERTAINTY

The Company has long-term, firm resources from which it can supply over 98 percent of its annual energy requirements. The small shortfall is due to system capacity constraints during peak load days. An advance purchase of winter capacity blocks from Powerex has been obtained to meet the majority of the peak winter loads.

Concurrently with the 2012-13 RRA ,the Company filed its 2012 Integrated System Plan, one component of which is the 2012 Resource Plan . The 2012 Resource Plan reviews appropriate long term resource options to meet the Company's remaining energy requirements. Potential changes resulting from the 2012 Resource Plan will not impact resource acquisition during 2012 and 2013.

4.1.2.2 POWER PURCHASE COSTS

Power Purchase costs for 2012 and 2013 are shown in Tables 4.1.4-2 and 4.1.4-3. Where applicable, power purchase costs have been forecast using contract prices plus a forecast of future market prices.

The Company proposes to establish a deferral account to collect the difference between actual and approved 2012 and 2013 Power Purchase Expense as explained in Section 4.1.4.

Existing Resource Base and Long Term Purchases

FortisBC uses a combination of Company-owned generation entitlements and contracted firm supply to meet its load requirement. Any capacity or energy deficits that remain after using all other firm resources are met with short-term or spot market purchases. The Company's resources consist of:

A. FortisBC owned generation entitlements; with an estimated winter peak capacity of 227 MW in 2012 and 2013 (actual capacity will depend on the final CPA entitlement increases as a result of the ULE projects). There are no costs associated with FortisBC owned generation included in the power purchase estimates, except for the Balancing Pool adjustments, which account for the difference between energy entitlements and actual usage.

B. The Brilliant Power Purchase Agreement (BPPA) (a 129 MW contract terminating in 2056), and an amendment to the BPPA which reflects the purchase of the Brilliant Upgrade power (20 MW) and the Brilliant Tailrace Capacity agreement (5 MW);

C. The Company's Power Purchase Agreement with BC Hydro (200 MW) priced at BC Hydro's Rate Schedule 3808 (the BC Hydro PPA), which terminates September 30, 2013;

D. A number of small Independent Power Producer (IPP) contracts, and;

E. A number of market purchase arrangements described below.

A. FortisBC Owned Generation Entitlements

Company owned generation energy entitlements under the CPA are forecast as follows:

Table 4.1.2.2-1 CPA Energy Entitlement

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Entitlement Energy (GWh)	1,591	1,601	1,611	1,611
2	Change (%)			0.6%	0.0%
3	Outages/Spill (GWh)	-23	-14	-6	-6
4	Net Entitlement Energy (GWh)	1,568	1,587	1,604	1,604
5	Storage (GWh)	-37	17	-4	0
6	Usable Entitlement Energy (GWh)	1530	1604	1600	1604

The expected increased CPA entitlements are the result of the ULE program, which is scheduled to be complete by the end of 2011. The outage forecast for 2012 and 2013 is based on average actual loss of entitlement energy due to maintenance and forced outages between 2008 and 2010. In 2011 the Company forecasts that it will use 17 GWh of storage energy from the CPA Exchange accounts (balancing pool), and in 2012 it will store 4 GWh of energy. In 2013 the use of the storage account is balanced at 0 GWh for the year. The use of the storage account is the only portion of the CPA entitlement that is included in the Power Purchase expense forecast. When the Company stores energy, a credit is applied to Power Purchases, and when the Company uses energy, a charge is applied to Power Purchases. The Company uses the BC Hydro PPA rate prevalent at the end of the year to value this storage or usage.

Company owned generation capacity entitlements under the CPA are forecast as follows for December, the peak forecast month:

Table 4.1.2.2-2 CPA Winter Peak Capacity Entitlement

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Capacity at winter peak (MW)	223	225	227	227
2	Change (%)			0.9%	0.0%
3	Outages/Reserves (MW)	-26	-26	-10	-10
4	Forecast Usable Entitlement (MW)	197	199	216	216

FortisBC is required to hold reserves of 4.45 percent on CPA capacity entitlements. In 2011, the Company forecasts an outage of 16 MW over the winter peak to account for the ULE project at Corra Linn Unit 2. For 2012 and 2013 there are no forecast maintenance outages over the winter peak.

B. Brilliant Power Purchase Agreement and Tailrace Agreement

The Company purchases power under the BPPA and under the Brilliant Power Purchase Second Amendment Agreement, both of which have been approved by the Commission.

The prices paid under the BPPA are based on forecasts of the annual operating and maintenance costs and capital charges for the plant.

The price for the Brilliant Power Purchase Second Amendment Agreement is as follows: for the unregulated-flow component of the upgrade power, price is based on a forecast of the all-in capital cost of the upgrades. The regulated-flow component was recalled by the owner in late 2005 and no regulated upgrade energy is expected to be available for purchase in 2012 or 2013.

A forecast of the prices and usage of energy from the Brilliant Plant under long-term contract is as follows:

Table 4.1.2.2-3 Brilliant Energy Purchases

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Base Volume (GWh)	859	859	859	859
2	Base ($/MWh)	36.45	35.31	39.14	40.46
3	Change (%)		-3.1%	10.8%	3.4%
4	Upgrade Volume (GWh)	65	65	65	65
5	Upgrade - Unregulated ($/MWh)	26.55	27.19	27.87	28.56
6	Change (%)		2.4%	2.5%	2.5%
7	Outages (GWh)	-2.8	-2.5	-3.5	-3.5
8	Total Usable Brilliant Dam (GWh)	922	922	921	921

As in the past, the base rate for 2011 and 2012 includes a “true-up” adjustment for prior years, which is the difference between the forecast and actual costs as allowed under the Agreements. For 2011 the adjustment amounts to a decrease in costs of $2.1 million, based on the difference between forecast and actual costs for 2008 and 2009. For 2012, the adjustment amounts to a decrease of approximately $0.1 million, based on the actual costs for 2010. The Company proposes that the true-up of the BPPA costs be included in the Power Purchase Variance Deferral Account described in section 4.1.4. The Power Purchase Variance Deferral Account is not approved, the true-up of BPPA costs would remain a component of Power Purchase Expense.

The Company bases the Brilliant maintenance outages on the average loss of energy due to forced and maintenance outages between 2008 and 2010, and has included an energy reduction for the planned maintenance outage in March of each year.

In addition to the energy, the Company also receives the associated capacity from the Brilliant plant. The cost for the capacity is included in the energy rates shown above in Table 4.1.2.2-3. Furthermore, the Company has long-term rights to approximately 5 MW of capacity under the Brilliant Tailrace Agreement, also approved by the Commission. A forecast of the price and usage of capacity from the Brilliant Plant under the long-term contracts is as follows:

Table 4.1.2.2-4 Brilliant Winter Peak Capacity Purchases

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Base Capacity	129	129	129	129
2	Upgrade Capacity	20	20	20	20
3	Tailrace Capacity	5	5	5	5
4	Tailrace ($/MW/Month)	3,897	3,968	4,041	4,115
5	Change (%)		1.8%	1.8%	1.8%
6	Outages/Reserves (MW)	-7	-7	-7	-7
7	Forecast Usable Capacity (MW)	147	147	147	147

The Company is required to hold reserves of 4.45 percent on the Base and Upgrade Brilliant Capacity, consistent with the reserves held on FortisBC entitlement resources. Columbia Power Corporation (CPC) holds the reserve on the Tailrace capacity. For 2011, 2012 and 2013 there are no forecast maintenance outages over the winter peak from Brilliant.

C. BC Hydro

The BC Hydro PPA will expire in September of 2013. For this Application the contract has been assumed to be renewed on similar terms. The rates and usage of the BC Hydro PPA are shown in Table 4.1.2.2-5 below:

Table 4.1.2.2-5 BC Hydro 3808 Purchases

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Energy (GWh)	600	708	991	1020
2	Average $/MWh	32.36	35.28	38.19	41.23
3	Change (%)		9.0%	8.2%	8.0%
4	Capacity (MW)	200	200	200	200
5	$/MW/Month	5,478	5,976	6,549	7,073
6	Change (%)		9.1%	9.6%	8.0%

The Company has used BC Hydro's current interim rates as at May 1, 2011, including the deferral account rate rider. Forecast BC Hydro rate increases of 8 percent commencing April 1, 2012 and April 1, 2013 are also included. The Company proposes that any variances in BC Hydro rates between forecast and actual be included in the Power Purchase Variance Deferral Account described in section 4.1.4. If the Power Purchase Variance Deferral Account is not approved, the Company expects to flow through changes in BC Hydro rates at the time they are approved, as it currently does.

D. Independent Power Producers

The Company has eight small power purchase contracts with IPPs from which FortisBC is supplied energy, but no capacity. Table 4.1.2.2-6 shows the forecast rates and usage from IPPs.

Table 4.1.2.2-6 IPP Purchases

	Energy	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Volume (GWh)	37	5	4	4
2	Change (%)		-87.4%	-4.6%	0.0%
3	$/MWh	24.84	32.68	34.64	35.33
4	Change (%)		31.6%	6.0%	2.0%

The IPP rates are based on actual rates paid to the IPPs between 2008 and 2010, escalated by the forecast change in the BC Consumer Price Index (CPI). The weighted average IPP rate is slightly lower than the BC Hydro PPA rate.

E. Market Purchases

Based on current resources and long-term agreements, the Company is resourced for almost all of its energy needs, but only 78 percent of the winter peak capacity. In order to meet the Company's peak demands, market purchases of power are required.

For 2012 and 2013 the Company uses (i) Market Purchases Made in Advance and (ii) Spot Market Purchases, described below.

(i) Market Purchases Made in Advance

For the last few years, cost-effective capacity block purchases from Teck Metals Ltd. (Teck) have been available. With the sale of one third of Teck's Waneta plant to BC Hydro in 2010, capacity purchases for the winter months are no longer available from Teck. As a result of this transaction, FortisBC entered into a five year deal with Powerex to provide winter capacity blocks to replace what was previously available from Teck. Table 4.1.2.2-7 below is a summary of capacity purchases from Powerex in 2012 and 2013.

Table 4.1.2.2-7 Powerex Capacity Block Purchases

	Month	Amount (MW)	Total Cost ($US)	$US/MW
1	January 2012	150	899,550	5,997
2	February	75	449,775	5,997
3	November	50	337,350	6,747
4	December	125	843,375	6,747
5	January 2013	150	1,012,050	6,747
6	February	75	506,025	6,747
7	November	50	352,700	7,054
8	December	125	881,750	7,054

. While these capacity blocks help to meet the winter peak, the Company still has a capacity deficit of 32 MW in 2012 and 43 MW in 2013. The Company anticipates meeting these peaks with spot market purchases or purchases made in advance of the expected need.

(ii) Spot Market Purchases

Any remaining peak requirements will be purchased on a day-ahead or real-time basis with the forecast rates as follows:

Table 4.1.2.2-8 Spot Market Purchases for Capacity

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Peak Month Capacity Deficit (MW)	206	41	32	43
2	Volume (GWh)	78	70	4	4
3	$/MWh	39.73	35.29	48.76	58.60
4	Change (%)		-11.2%	38.2%	20.2%

The FortisBC capacity deficit in 2010 was a result of the peak demand occurring in late November, and the Company not having sufficient capacity blocks in place to meet the unexpectedly heavy November load. Had the peak demand occurred in January or December the amount of short-term market purchases required to meet peak demand would have been significantly less, since the winter peak is anticipated to occur in those months and more capacity block resources are available. The amount of energy required to meet peak capacity demand is calculated based on the Company's expected load duration curves. These load curves are forecast based on the average monthly load curves calculated from actual load data for the FortisBC system from 2007 to 2010, which is then escalated by the difference between the peak average hourly load, and the peak load forecast. For 2012, the Company is forecasting a 32 MW deficit on its winter peak demand. Based on the Company's forecast load curves, it will have a deficit for the 9 peak hours of the month, and will require purchases of 115 MWh to cover this deficit. However, in real-time it is impossible to purchase exactly what is needed due to uncertainty in the hourly load forecast and other system conditions. For each hour that the Company is expected to be in the market to meet capacity, it is anticipated that the real-time operator will, on average, purchase at least 10 MW more than what is required to account for variations in the load forecast within the hour. As a result an additional 10 MW of purchases for every hour that the Company is anticipated to be in the market has been included. For December 2012, this accounts for an additional 90 MWh of purchases. In both 2012 and 2013, the Company is forecasting a capacity deficit for 7 months of the year, ranging from 1 hour of the month to 61 hours.

The forecast market prices are based on a variety of sources, including an April 29, 2011 Argus Media Publication titled "Argus US Electricity", and consultations with both Shell Energy North America and Powerex. These sources are used to derive a monthly Mid-Columbia (Mid-C) price forecast, and using the methodology described in Section 4.1.2.3 to extrapolate an hourly price forecast. The hourly forecast is used to estimate the cost of meeting the Company's peak demand shortfall, and the cost to meet the Company's energy deficit. The lower rate in 2011 as compared to 2012-2013 is related to attractive prices during the first quarter of 2011 as well as buying market energy to meet load in additional hours beyond the very peak hours to displace BC Hydro capacity.

Spot market purchases to meet peak capacity requirements are expected to be approximately $0.2 million in 2012 and 2013 compared to $2.5 million in 2011. The quantity of spot market purchases for capacity in 2011 is above what is forecast for 2012 and 2013 because market prices were low enough in the first four months of 2011 to make these opportunities possible. Additionally, the Company was buying market energy to meet load in additional hours beyond the very peak hours to displace BC Hydro capacity. Unforeseen market conditions in the first four months of 2011 made these opportunities possible.

In addition to purchasing for capacity, the Company also makes market purchases for energy to fill any deficit in firm energy supply, to displace BC Hydro energy at a lower cost, to fill the CPA Exchange accounts and to meet increased load. Table 4.1.2.2-9 below shows the forecast volume and rate of market purchases for energy.

Table 4.1.2.2-9 Spot Market Purchases for Energy

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Volume (GWh)	212	205	0	5
2	$/MWh	24.06	8.44	53.04	60.08
3	Change (%)		-64.9%	528.8%	13.3%

It is anticipated that less than 1 GWh in 2012 and approximately 5 GWh in 2013 of non-BC Hydro PPA power (market energy) will be required in order to maintain appropriate energy reserves. While the amount of the energy deficit is small in 2012 and 2013, the Company's energy deficit will continue to grow.

The Company's estimate of 2011 Power Purchase Expense includes actual market purchases to April 30, 2011, and a forecast of market purchases for the remainder of the year based on current market forecasts. Because of this, the quantity of market purchases for energy is substantially larger in 2011 than in 2012 and 2013. While the Company does not forecast any of these opportunities in 2012 and 2013, a reduction of $0.75 million to Power Purchase Expense is included in each year, to account for potential savings due to similar opportunities.

The total cost of purchases from the market (market purchases made in advance and spot market purchases) is expected to be approximately $2.7 million in 2012 and $3.4 million in 2013, compared to approximately $6.5 million in 2011.

4.1.2.3 MARKET PRICE FORECAST METHODOLOGY

FortisBC's market forecast for Mid-C energy is based on a variety of sources, including an April 29, 2011 Argus Media Publication titled "Argus US Electricity", and consultations with both Shell Energy North America and Powerex. Based on these sources, the Company's acquires two monthly forecasts, one for heavy load hours (HLH) and one for light load hours (LLH). This provides the monthly block price of both heavy load and light load energy for a twelve month period. In order to get the energy from the MID-C to the FortisBC service territory, the Company applies a cost of $4 USD/MWh to the forecast Mid-C price as a transmission charge. The Company escalates this forecast based on annual forecasts from the sources above, in order to extrapolate a 5 year market price forecast.

For market purchases required only for energy (line 37 in Tables 4.1.4-2 and 4.1.4-3), the Company assumes that the block rate is the rate that it will be required to be paid. For market purchases required to meet peak demand (line 38 in Tables 4.1.4-2 and 4.1.4-3), it is assumed that the Company will only be in the market for the peak hours of the month. FortisBC's peak hours for any month are usually the same peak hours as the rest of the Northwest Power Pool, which usually causes increased prices during these peak hours and peak days. Because of this, the Company anticipates that the block price for all heavy load hours will not accurately reflect the cost that the Company expects to pay to for capacity to meet its peak demand. The Company adds a conservative 20 percent premium to the block forecast of heavy load energy to account for the peak hour premium. Additionally, these forecasts are converted to Canadian dollars, based on the Company's forecast exchange rates (line 46 of Tables 4.1.4-2 and 4.1.4-3).

4.1.2.4 MARKET ACTIVITY

In addition to using the market for capacity and energy deficits, the Company will continue its strategy of attempting to supply its energy and capacity needs at the lowest cost throughout the year using the real-time market, as well as purchases made in advance. The possibilities for savings depend on market prices and system requirements, and the Company is not always able to forecast these savings in advance. For example, in the first four months of 2011, the

Company has been able to take advantage of market prices which were well below the forecast market prices at the time of the 2011 Revenue Requirements Application. While the current market price forecasts are not looking as favourable as what has been experienced so far in 2011, the Company has included a $0.75 million reduction to Power Purchase Expense in each of 2012 and 2013 to account for potential market savings as discussed above.

4.1.2.5 PLANNING RESERVE MARGIN

The Company is implementing a planning reserve margin (PRM) in 2012. The amount of PRM required is shown in line 30 of Tables 4.1.4-2 and 4.1.4-3, and is calculated based on the "FortisBC Inc. Planning Reserve Margin Report" provided as Appendix E to the 2012 Resource Plan. For the duration of the current PPA with BC Hydro, FortisBC will meet this planning reserve requirement through its PPA with BC Hydro. The agreement states that BC Hydro will use "reasonable efforts" to supply FortisBC's load beyond the 200 MW contract amount, and the Company believes that while this contractual arrangement is a non-firm resource, it is a reliable source of PRM. There is no cost to hold this PRM under the PPA and since it is not expected to be used, no cost has been included as part of Power Purchase Expense.

The BC Hydro PPA expires September 2013, at which point the Company believes that it is prudent to secure a PRM resource from another source. While the source of the PRM is unclear at this time, PRM costs have been included from October 1, 2013 onwards, based on estimates provided by Midgard Consulting. The PRM cost in 2013 is forecast to be $0.311 million.

4.1.2.6 POWER PURCHASE MANAGEMENT EXPENSES

The Company has included a portion of the management expense required to manage power purchase costs in 2012 and 2013 in the estimate of the total Power Purchase Expense and excluded it from the Operating and Maintenance (O&M) budget. The Power Purchase Management Expense (PPME) amount equals $1.2 million in 2012 and $1.3 million in 2013. This change to how this expense is treated is being made to help ensure that the resources required to plan, implement and mitigate Power Purchase Expense are sufficient. This is achieved by linking this expense directly to the overall Power Purchase Expense rather than as a component of the O&M budget.

Power Supply is the group responsible for planning and securing power on a short (hourly and daily), medium (monthly and seasonally), and long-term basis. The sources of power are Company owned generating units, power supply contracts, and market transactions that range from hourly to several months. The group is also responsible for selling any surpluses that may accumulate during spring runoff. Power Supply also plays a key role helping to provide direction to System Operations so that daily scheduling and back-office accounting processes, which are critical to the recording of the Power Purchase Expense, are optimized. Underpinning these purchase and sales activities are credit control measures that help to ensure market transactions are executed successfully.

The Power Supply group faces the need to secure increasing future load that must be met in a regional environment that is becoming more constrained and more tightly regulated. Underpinning the Company's ability to secure load requirements, are critical contract negotiations and renewals that will set the direction of the Company's Power Supply portfolio for the next 20 to 40 years. Generation and contractual resources need to be managed carefully to maximize value in an increasingly complex environment. Increased complexity of the operating environment requires a significant increase in regional working group participation, such as the North West Power Pool (NWPP) and Western Electricity Coordinating Council (WECC).

This Application includes incremental staff and funding for Power Supply that the Company believes is required to help ensure that it continues to be able to successfully manage the growing complexities in meeting increasing load as efficiently as possible. This additional funding would also allow for the further optimization of the Power Purchase Expense, dealing with transmission paths that are becoming more constrained, and allow for better price forecasting.

Table 4.1.2.6-1 Summary of Power Purchase Management Expense and Full Time Equivalents (2007-2013)

	General Assumptions	**2007A**	**2008A**	**2009A**	**2010 A**	**2011F**	**2012F**	**2013F**
1.0	**Full Time Equivalents (FTE):**		3	4	6	6	7	7
		($000s)						
2.0	**Expenses**							
2.1	Labour		514	583	629	724	923	957
2.2	Non Labour		32	156	198	203	288	309
TOTAL O&M EXPENDITURE:		-	546	739	827	927	1,211	1,266

The Power Purchase Management Expense in 2012 is expected to increase by $0.284 million. This increase is comprised of:

- $0.022 million for labour cost escalation, net of time charged to projects;
- $0.143 million for the loaded labour cost associated with the planned addition of one Full Time Equivalent employee (FTE);
- $0.068 million for the need for additional consulting resources; and
- $0.050 million for intercompany transfers from FortisBC Energy Inc. (FEI) for services it will be providing to the Power Supply group.

With the exception of the escalation applicable to labour, all other forecast cost increases are associated with the need for the Power Supply group to successfully manage the increasing complexities in meeting greater load, to allow for the further optimization of the Power Purchase Expense, to better manage transmission paths that are becoming more constrained, and to enable better price forecasting. The additional FTE is expected to assist the current staffing in the completion of the core Power Supply responsibilities described earlier in this section. Consulting expertise by third parties is required to provide analysis and advice on a range of potential issues the group faces with the increase in complexities in meeting greater load and the need to further optimize the cost of power. FEI will be providing a range of business planning, contracting review, market analysis, financial credit, and compliance review services that Power Supply increasingly requires but is unable to provide cost effectively on its own.

PPME costs in 2013 are expected to increase by $0.055 million, which is limited to inflationary changes affecting labour and some non-labour costs.

The successful completion of the Power Supply activities described in this section of the Application underpins the Company's ability to successfully manage Power Purchase Expense. The Company believes the management expenses presented in this Application are prudent and necessary to help ensure safe and reliable service to customers.

The Company notes that if the inclusion of the PPME costs in Power Purchase Expense is not approved by the Commission, the costs must be reclassified as Operating and Maintenance Expense.

4.1.3 Surplus Sales

The Company has small amounts of surplus available in the months of May, June and July because its firm resources, including the entitlements under the CPA, exceed the load requirements in that period.

As a result of the one third sale of the Waneta Dam to BC Hydro, the Company entered into a five year deal with Powerex to sell its summer surplus energy. The Company expects to exercise this deal in July 2011, and currently forecasts 15 GWh in surplus sales, compared to the 2011 approved amount of 26 GWh. The reduction from approved is due to energy lost as a result of the ULE project at Corra Linn Unit 2 commencing in June rather than in August as previously planned, as well as a 3 GWh increase in forecast load.

Table 4.1.3 Summer Surplus Sales

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Volume (GWh)	49	15	19	16
2	Change (%)		-70%	27%	-17%
3	$/MWh	18.60	17.50	15.16	16.92
4	Change (%)		-6%	-13%	12%

Overall the revenue from summer surplus sales is expected to be approximately $0.3 million in each of 2011, 2012 and 2013.

4.1.4 Total Power Purchase Expense

Detail of the forecast Power Purchase Expense for 2011, 2012, and 2013 are provided in Tables 4.1.4-1, 4.1.4-2, and 4.1.4-3, respectively.

Table 4.1.4-1 2011 Estimated Power Purchase Expense

	2011	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		Actual	Actual	Actual	Estimate	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
1	**Energy (GWh)**													
2	FortisBC Resources	142	161	131	118	117	98	174	128	118	122	115	170	**1,594**
3	Turbine Upgrades	0	0	0	1	1	1	1	1	1	1	1	1	**10**
4	Brilliant Base Plant	82	63	57	82	79	72	79	86	66	62	63	65	**857**
5	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	**65**
6	Total BCH 3808 Energy	84	54	56	6	15	24	30	37	46	81	132	144	**708**
7	Net IPP Generation	0	0	1	0	0	0	1	0	0	0	0	0	**4.68**
8	Market Energy	36	31	44	44	20	30	0	0	0	0	0	0	**205**
9	Market Capacity - Energy	21	22	22	2	0	1	1	0	0	0	0	0	**70**
10	Operating Reserve	0	0	0	0	0	0	0	0	0	0	0	0	**-**
11	DSM and Other Customer Savings	0	0	0	0	1	1	2	2	2	2	3	3	**15**
12	Loss Recovery	1	1	1	0	0	0	0	0	0	0	0	0	**2**
13	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	**-**
14	WEPAS Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	**(0)**
15	FBC Surplus Sales	0	0	0	0	0	0	-15	0	0	0	0	0	**(15)**
16														**-**
17	**Total Gross Load (GWh)**	**367**	**331**	**310**	**263**	**247**	**241**	**287**	**267**	**235**	**269**	**315**	**384**	**3,517**
18	Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0
19														
20	**Capacity (MW)**													**Total**
21	FortisBC Resources	195	192	186	180	172	163	173	203	206	207	198	197	**2,272**
22	Turbine Upgrades	0	0	0	0	0	0	0	0	2	2	2	2	**9**
23	Brilliant Base Plant	123	123	102	117	106	100	106	115	119	119	123	123	**1,375**
24	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	**238**
25	Brilliant Tailrace	0	3	1	2.5	6	6	5.7	3.6	0.9	0.9	3.4	4.8	**38**
26	BCH Billing Capacity	162	153	152	136	136	136	200	194	150	170	200	200	**1,989**
27	BCH Peak Usage	150	140	140	136	136	136	200	194	97	170	200	200	**1,899**
28	BCH Excess Capacity	0	0	0	0	0	0	0	0	0	0	0	0	**-**
29	Powerex Capacity Blocks	150	75	0	0	0	0	0	0	0	0	50	125	**400**
30	CPC Capacity Blocks	0	0	0	0	34	27	0	0	0	0	0	0	**61**
31	Real Time Market Purchases	25	125	95	50	0	46	56	0	0	1	10	39	**446**
32	DSM and Other Customer Savings	0	0	0	0	2	2	3	3	4	4	4	5	**26**
33														
34	**FBC Peak Load (MW)**	**652**	**669**	**582**	**477**	**455**	**499**	**563**	**539**	**448**	**523**	**610**	**715**	**6,731**

Table 4.1.4-1 2011 Estimated Power Purchase Expense (cont'd)

	2011	Jan Actual	Feb Actual	Mar Actual	Apr Estimate	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
35	**Energy Rates (CDN$/MWh)**													**Average**
36	Brilliant Base Plant	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	35.31	**35.31**
37	Brilliant Upgrade	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	27.19	**27.19**
38	BCH 3808	31.95	31.95	31.95	33.53	36.21	36.21	36.21	36.21	36.21	36.21	36.21	36.21	**35.28**
39	IPP Rate	32.31	34.18	32.60	32.60	32.60	32.60	32.60	32.60	32.60	32.60	32.60	32.60	**32.68**
40	Market Energy	19.08	13.36	9.02	5.33	0.00	0.00	20.40	26.29	26.18	30.70	32.21	35.24	**8.44**
41	Market Capacity - Energy	34.06	36.59	34.63	41.02	21.95	20.98	38.09	49.68	48.23	47.27	49.43	54.19	**35.29**
42	Operating Reserve					22.50	21.51	39.45	51.45	49.95	49.20	51.45	56.40	**-**
43	Surplus Rate					4.21	3.77	17.50	23.39	23.28	27.82	29.33	32.35	**17.50**
44														
45	**Capacity Rates (CDN$/MW/month)**													
46	BRD Tailrace Capacity Rate	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	3,968	**3,968**
47	BCH 3808 Capacity Rate	5,451	5,451	5,451	5,721	6,178	6,178	6,178	6,178	6,178	6,178	6,178	6,178	**5,976**
48	Powerex Capacity Rate	5,713	5,677									5,762	5,762	**5,728**
49														
50	**Exchange Rate (CDN$/USD$)**	0.99	0.99	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.96	0.96	0.96	**0.97**
51														
52	**Energy Expense ($000s)**													**Total**
53	Brilliant Base Plant	2,893	2,227	2,083	2,890	2,801	2,551	2,802	3,041	2,335	2,199	2,224	2,299	**30,345**
54	Brilliant Upgrade	19	(17)	(12)	266	378	352	378	347	26	17	8	9	**1,770**
55	BCH 3808	2,692	1,714	1,778	185	527	885	1,090	1,342	1,681	2,930	4,785	5,201	**24,809**
56	BCH 3808 Excess/Unallocated costs	6	13	8	28	29.6	27.2	30.9	25.4	10.3	-	-	-	**178**
57	IPP Costs	16	11	17	4	14	14	20	8	15	13	14	7	**153**
58	Market Energy	682	418	394	237	-	-	-	-	-	-	-	-	**1,731**
59	Market Capacity - Energy	717	798	778	91	-	18	56	1	-	1	2	19	**2,480**
60	Operating Reserve	-	-	-	-	-	-	-	-	-	-	-	-	**-**
61														
62	**Total Energy Expense ($000s)**	**7,025**	**5,164**	**5,045**	**3,701**	**3,749**	**3,846**	**4,375**	**4,763**	**4,068**	**5,160**	**7,034**	**7,535**	**61,466**
63														
64	**Capacity Expense ($000)**													
65	BRD Tailrace Capacity	2	12	4	10	24	24	23	14	4	4	13	19	**152**
66	BCH 3808 Capacity	883	834	829	778	840	840	1,236	1,199	927	1,050	1,236	1,236	**11,887**
67	BCH 3808 Excess Capacity	-	-	-	-	-	-	-	-	-	-	-	-	**-**
68	Powerex Capacity	857	426	-	-	-	-	-	-	-	-	288	720	**2,291**
69														
70	**Total Capacity Expense ($000s)**	**1,742**	**1,272**	**833**	**788**	**864**	**864**	**1,258**	**1,213**	**930**	**1,054**	**1,537**	**1,975**	**14,330**
71														
72	**Other Expenses ($000s)**													
73	Surplus Revenue	-	-	-	-	-	-	(259)	-	-	-	-	-	**(259)**
74	Capital Project Recovery	(89)	(82)	(105)								(96)	(94)	**(467)**
75	Special & Accounting Adjustments	(27)	5		240.0	123	94						(76)	**360**
76	WEPAS Adjustment		29	(4)										**25**
77	Balancing Pool Adjustments	(212)	1,222	480	(714)	(652)	(760)	1,464	(724)	(525)	(163)	(290)	1,376	**501**
78														
79	**Total Other Expense ($000s)**	**(329)**	**1,173**	**371**	**(474)**	**(528)**	**(666)**	**1,205**	**(724)**	**(525)**	**(163)**	**(385)**	**1,206**	**160**
80														
81	**Total Power Purchase Expense**	**8,439**	**7,610**	**6,249**	**4,015**	**4,084**	**4,044**	**6,839**	**5,252**	**4,473**	**6,051**	**8,186**	**10,716**	**75,956**

Table 4.1.4-2 2012 Forecast Power Purchase Expense

	2012	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
1	**Energy (GWh)**													
2	FortisBC Resources	156	131	132	128	117	100	178	118	113	121	115	170	**1,581**
3	Turbine Upgrades	2	2	2	2	2	2	2	2	2	2	2	2	**20**
4	Brilliant Base Plant	82	63	57	82	79	72	79	85	66	62	63	65	**856**
5	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	**65**
6	Total BCH 3808 Energy	131	120	116	38	37	55	32	48	52	84	132	146	**991**
7	Net IPP Generation	0	0	1	0	0	0	0	0	0	0	0	0	**4**
8	Market Energy	0	0	0	0	0	0	0	0	0	0	0	0	**0**
9	Market Capacity - Energy	0	0	3	0	0	0	1	0	0	0	0	0	**4**
10	DSM and Other Customer Savings	3	4	4	4	4	4	4	5	5	5	6	6	**53**
11	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	**-**
12	WEPAS Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	**-**
13	FBC Surplus Sales	0	0	0	0	0	0	-19	0	0	0	0	0	**(19)**
14														**-**
15	**Total Gross Load (GWh)**	**375**	**319**	**314**	**263**	**253**	**246**	**292**	**271**	**238**	**275**	**319**	**390**	**3,555**
16	Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0
17														
18	**Capacity (MW)**													**Total**
19	FortisBC Resources	210	192	186	180	176	178	188	202	206	192	213	213	**2,335**
20	Turbine Upgrades	2	2	2	2	2	2	2	2	4	4	4	4	**27**
21	Brilliant Base Plant	123	123	87	117	106	100	106	81	119	119	123	123	**1,325**
22	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	**238**
23	Brilliant Tailrace	0	3	1	3	6	6	6	4	1	1	3	5	**38**
24	BCH Billing Capacity	180	200	200	175	150	198	200	200	150	190	200	200	**2,243**
25	BCH Peak Usage	180	200	200	175	149	198	200	200	99	190	200	200	**2,191**
26	Powerex Capacity Blocks	150	75	0	0	0	0	0	0	0	0	50	125	**400**
27	Market Purchases - Real Time	0	1	76	0	0	0	47	33	0	0	0	32	**189**
28	DSM and Other Customer Savings	5	6	5	6	6	7	7	8	8	8	9	9	**83**
29	**FBC Peak Load (MW)**	**677**	**620**	**577**	**502**	**464**	**509**	**575**	**550**	**457**	**533**	**622**	**730**	**6,816**
30	Planning Reserve Margin	52	49	47	42	38	38	43	44	40	43	49	54	**537**
31	**Total Capacity Planning Load (MW)**	**729**	**669**	**623**	**543**	**502**	**548**	**617**	**594**	**496**	**577**	**671**	**783**	**7,353**

Table 4.1.4-2 2012 Forecast Power Purchase Expense (cont'd)

	2012	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
32	**Energy Rates (CDN$/MWh)**													**Average**
33	Brilliant Base Plant	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	39.14	**39.14**
34	Brilliant Upgrade	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	27.87	**27.87**
35	BCH 3808	36.21	36.21	36.21	39.11	39.11	39.11	39.11	39.11	39.11	39.11	39.11	39.11	**38.38**
36	IPP Rate	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	34.64	**34.64**
37	Market Energy	39.00	37.07	34.42	21.91	12.97	8.26	19.87	36.74	40.86	46.31	50.30	53.04	**53.04**
38	Market Capacity - Energy	53.84	50.94	48.05	42.15	34.51	23.20	41.68	63.39	62.88	64.66	66.02	70.14	**48.76**
39	Surplus Rate	33.49	31.69	29.21	17.20	8.99	4.65	15.16	30.54	34.29	38.99	42.60	45.08	**15.16**
40														
41	**Capacity Rates (CDN$/MW/month)**													
42	BRD Tailrace Capacity Rate	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	**4041**
43	BCH 3808 Capacity Rate	6,178	6,178	6,178	6,672	6,672	6,672	6,672	6,672	6,672	6,672	6,672	6,672	**6549**
44	Powerex Capacity Rate	5,786	5,786	-	-	-	-	-	-	-	-	6,701	6,701	**2081**
45														
46	**Exchange Rate (CDN$/USD$)**	0.96	0.96	0.96	0.98	0.98	0.98	0.99	0.99	0.99	0.99	0.99	0.99	**0.98**
47														
48	**Energy Expense ($000)**													
49	Brilliant Base Plant	3,207	2,468	2,309	3,203	3,104	2,828	3,105	3,371	2,588	2,438	2,465	2,548	**33,634**
50	Brilliant Upgrade	20	(18)	(12)	273	387	361	387	355	27	17	8	9	**1,814**
51	BCH 3808	4,740	4,363	4,208	1,490	1,434	2,133	1,242	1,890	2,033	3,273	5,177	5,705	**37,688**
52	BCH 3808 Excess	-	-	0	12	32	29	33	27	11	0	5	0	**152**
53	IPP Costs	12	17	19	7	17	14	13	10	10	16	12	8	**155**
54	Market Energy	-	-	-	-	-	-	-	-	-	-	-	10	**10**
55	Market Capacity - Energy	-	1	132	-	-	0	38	17	-	1	1	14	**204**
56														
57	**Total Energy Expense ($000s)**	**7,979**	**6,831**	**6,655**	**4,985**	**4,975**	**5,365**	**4,819**	**5,671**	**4,670**	**5,744**	**7,669**	**8,295**	**73,657**
58														
59	**Capacity Expense ($000)**													
60	BRD Tailrace Capacity	-	12	4	10	24	24	23	15	4	4	14	19	**153**
61	BCH 3808 Capacity	1,112	1,236	1,236	1,168	1,001	1,321	1,334	1,334	1,001	1,268	1,334	1,334	**14,680**
62	Powerex Capacity	868	434	-	-	-	-	-	-	-	-	335	838	**2,475**
63														
64	**Total Capacity Expense ($000s)**	**1,980**	**1,682**	**1,240**	**1,178**	**1,025**	**1,345**	**1,358**	**1,349**	**1,004**	**1,271**	**1,683**	**2,192**	**17,307**
65														
66	**Other Expenses ($000)**													
67	Surplus Revenue	-	-	-	-	-	-	(284)	-	-	-	-	-	**(284)**
68	Capital Project Recovery													**-**
69	Special & Accounting Adjustments													
70	Market Adjustment	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	**(750)**
71	Balancing Pool Adjustments	313	274	602	(368)	(704)	(899)	1,603	(1,173)	(782)	(196)	(313)	1,486	**(156)**
72	Planning Reserve Margin	-	-	-	-	-	-	-	-	-	-	-	-	**-**
73	Management Expense	101	101	101	101	101	101	101	101	101	101	101	101	**1,211**
74														
75	**Total Other Expense ($000s)**	**351**	**312**	**641**	**(329)**	**(665)**	**(861)**	**1,357**	**(1,135)**	**(744)**	**(157)**	**(274)**	**1,524**	**20**
76														
77	**Total Power Purchase Expense**	**10,310**	**8,824**	**8,535**	**5,833**	**5,334**	**5,849**	**7,534**	**5,886**	**4,930**	**6,859**	**9,077**	**12,011**	**90,984**

Table 4.1.4-3 2013 Forecast Power Purchase Expense

	2013	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
1	**Energy (GWh)**													
2	FortisBC Resources	156	131	132	132	117	100	178	118	113	121	115	170	**1,585**
3	Turbine Upgrades	2	2	2	2	2	2	2	2	2	2	2	2	**20**
4	Brilliant Base Plant	82	63	57	82	79	72	79	85	66	62	63	65	**856**
5	Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	**65**
6	Total BCH 3808 Energy	136	124	121	37	39	57	32	51	54	87	136	146	**1,020**
7	Net IPP Generation	0	0	1	0	0	0	0	0	0	0	0	0	**4**
8	Market Energy	0	0	0	0	0	0	0	0	0	0	0	5	**5**
9	Market Capacity - Energy	0	0	2	0	0	0	1	0	0	0	0	0	**4**
10	DSM and Other Customer Savings	7	7	7	7	7	7	7	8	8	8	9	9	**89**
11	City of Nelson Special Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	**-**
12	WEPAS Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	**-**
13	FBC Surplus Sales	0	0	0	0	0	0	-16	0	0	0	0	0	**(16)**
14														**-**
15	**Total Gross Load (GWh)**	**383**	**326**	**321**	**269**	**259**	**252**	**298**	**277**	**244**	**281**	**325**	**398**	**3,632**
16	Surplus	0	0	0	0	0	0	0	0	0	0	0	0	0
17														
18	**Capacity (MW)**													**Total**
19	FortisBC Resources	210	192	199	191	187	178	188	202	206	191	213	213	**2,370**
20	Turbine Upgrades	4	4	4	4	4	4	4	4	4	4	4	4	**43**
21	Brilliant Base Plant	123	123	87	117	106	100	106	81	119	119	123	123	**1,325**
22	Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	**238**
23	Brilliant Tailrace	0	3	1	2.5	6	6	5.7	3.6	0.9	0.9	3.4	4.8	**38**
24	BCH Billing Capacity	186	200	200	168	150	200	200	200	150	198	200	200	**2,252**
25	BCH Peak Usage	186	200	200	168	142	200	200	200	105	198	200	200	**2,199**
26	Powerex Capacity Blocks	150	75	0	0	0	0	0	0	0	0	50	125	**400**
27	Market Purchases - Real Time	0	7	69	0	0	2	53	39	0	0	10	43	**222**
28	DSM and Other Customer Savings	9	10	10	10	10	11	11	12	13	12	13	13	**135**
29	**FBC Peak Load (MW)**	**692**	**633**	**589**	**512**	**474**	**520**	**587**	**562**	**467**	**545**	**636**	**745**	**6,961**
30	Planning Reserve Margin	52	49	47	42	38	39	43	44	40	44	49	54	**542**
31	**Total Capacity Planning Load (MW)**	**744**	**682**	**636**	**554**	**512**	**559**	**630**	**606**	**506**	**589**	**685**	**799**	**7,503**

Table 4.1.4-3 2013 Forecast Power Purchase Expense (cont'd)

	2013	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
32	**Energy Rates (CDN$/MWh)**													**Average**
33	Brilliant Base Plant	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	40.46	**40.46**
34	Brilliant Upgrade	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	**28.56**
35	BCH 3808	39.11	39.11	39.11	42.24	42.24	42.24	42.24	42.24	42.24	42.24	42.24	42.24	**41.45**
36	IPP Rate	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	35.33	**35.33**
37	Market Energy	45.48	43.23	40.13	25.17	14.91	9.49	22.65	41.87	46.57	52.46	56.97	60.08	**60.08**
38	Market Capacity - Energy	63.94	60.50	57.07	49.33	40.39	27.16	48.38	73.58	72.99	74.60	76.17	80.93	**58.60**
39	Surplus Rate	37.07	35.08	32.35	19.15	10.09	5.31	16.92	33.89	38.03	43.23	47.21	49.95	**16.92**
40														
41	**Capacity Rates (CDN$/MW/month)**													
42	BRD Tailrace Capacity Rate	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	4,115	**4115**
43	BCH 3808 Capacity Rate	6,672	6,672	6,672	7,206	7,206	7,206	7,206	7,206	7,206	7,206	7,206	7,206	**7073**
44	Powerex Capacity Rate	6,882	6,882	-	-	-	-	-	-	-	-	7,195	7,195	**2346**
45														
46	**Exchange Rate (CDN$/USD$)**	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	**1.02**
47														
48	**Energy Expense ($000s)**													
49	Brilliant Base Plant	3,315	2,552	2,387	3,311	3,209	2,923	3,210	3,485	2,675	2,520	2,549	2,634	**34,770**
50	Brilliant Upgrade	20	(18)	(13)	280	397	369	397	364	28	17	8	9	**1,859**
51	BCH 3808	5,303	4,858	4,715	1,562	1,665	2,414	1,342	2,156	2,293	3,663	5,754	6,162	**41,886**
52	BCH 3808 Excess	-	-	0	13	35	32	36	30	12	0	6	0	**164**
53	IPP Costs	12	17	19	7	17	14	13	11	10	16	12	8	**158**
54	Market Energy	-	-	-	-	-	-	-	-	-	-	-	304	**304**
55	Market Capacity - Energy	-	2	118	-	-	0	57	27	-	-	3	34	**241**
56														
57	**Total Energy Expense ($000s)**	**8,650**	**7,411**	**7,226**	**5,173**	**5,323**	**5,753**	**5,055**	**6,072**	**5,019**	**6,217**	**8,331**	**9,151**	**79,381**
58														
59	**Capacity Expense ($000s)**													
60	BRD Tailrace Capacity	-	12	4	10	25	25	23	15	4	4	14	20	**155.547**
61	BCH 3808 Capacity	1,241	1,334	1,334	1,211	1,081	1,441	1,441	1,441	1,081	1,427	1,441	1,441	**15,916**
62	Powerex Capacity	1,032	516	-	-	-	-	-	-	-	-	360	899	**2,808**
63														
64	**Total Capacity Expense ($000s)**	**2,273**	**1,863**	**1,339**	**1,221**	**1,106**	**1,466**	**1,465**	**1,456**	**1,085**	**1,431**	**1,815**	**2,360**	**18,879**
65														
66	**Other Expenses ($000s)**													
67	Surplus Revenue	-	-	-	-	-	-	(267)	-	-	-	-	-	**(267)**
68	Planning Reserve Margin										88	102	121	**311**
69	Capital Project Recovery													**-**
70	Special & Accounting Adjustments													
71	Market Adjustment	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	**(750)**
72	Balancing Pool Adjustments	338	296	650	(228)	(760)	(971)	1,732	(1,267)	(845)	(211)	(338)	1,605	**-**
73	Previous Year True-up													
74	Management Expense	106	106	106	106	106	106	106	106	106	106	106	106	**1,266**
75														
76	**Total Other Expense ($000s)**	381	339	693	(185)	(717)	(928)	1,508	(1,224)	(802)	(80)	(193)	1,769	**561**
77														
78	**Total Power Purchase Expense**	**11,305**	**9,612**	**9,258**	**6,209**	**5,711**	**6,291**	**8,028**	**6,304**	**5,302**	**7,567**	**9,953**	**13,281**	**98,821**

4.1.5 Power Purchase Expense Variance Deferral Account

In this Application, FortisBC proposes a deferral account to capture variances between forecast and actual Power Purchase Expense. In previous years, expense variances related to the BPPA have been recorded in accounts payable and flowed through to Power Purchase Expense in the following year, as described in section 4.1.2.2 above. BC Hydro rate increases, which typically are not known at the time of FortisBC's Revenue Requirements Application (RRA) determinations, have been flowed through to customers by way of a mid-year rate adjustment. Utilizing the requested deferral account, 2012 and 2013 variances from all sources would be netted in a single account to be flowed through to rates in 2014.

Variances in Power Purchase Expense during the test years may result from:

1 Load variances due to variances in customer growth, usage, or weather;

2 Unit price variances from forecast, including market prices compared to forecast and regulated price changes (BC Hydro rates) not known at the time of application:

3 The Company's ability to displace BC Hydro purchases with lower-cost market purchases;

4 True-up of BPPA costs; or

5 Factors related to the operation of the CPA affecting the Company's usage or timing of entitlements.

Table 4.1.5-1 below shows the load variance and Power Purchase Expense variance for the years 2007 to 2011 (forecast).

Table 4.1.5-1 Sales Load and Power Purchase Expense Variance 2007 – 2011

	2007	2008	2009	2010	2011F	Total
			Over/(Under) Approved			
Sales Load Variance (GWh)	13	-	50	(153)	25	
Sales Load Variance (%)	0.4%	-	1.6%	-4.8%	0.8%	
Power Purchase Expense Variance ($000s)	(2,631)	(2,528)	(168)	(8,444)	(5,256)	(19,027)
Power Purchase Expense Variance (%)	-3.8%	-3.7%	-0.2%	-10.5%	-6.5%	

The 2007-2011 Performance Based Regulation (PBR) Plan provided that these variances were effectively shared equally with customers through the Return on Equity (ROE) Sharing Mechanism. During this period, revenue requirements will have been reduced by 50 percent of the total variance, or $9.5 million. Stakeholders at the 2011 RRA Negotiated Settlement

Agreement (NSA) noted that BC Hydro employs the Heritage Deferral and Non-Heritage Deferral Accounts for the true-up of power purchases and requested the Company to consider the use of a deferral account to true up Power Purchase Expense. The FortisBC Energy Utilities (FEU) also employ true-up mechanisms for natural gas commodity purchases.

The Company has considered this issue, and believes that it is reasonable to establish a deferral account for the total variance in Power Purchase Expense to effect the flow through of 100 percent of variances. This mechanism, if in place beginning in 2007, would have resulted in offsets to customer rates totalling $19.0 million as compared to only half of that benefit through the ROE sharing mechanism that was in place for this period.

As this Application requests firm rates to be set for 2012 and 2013, the Company proposes that the variance accumulated in the Power Purchase Expense deferral account be applied to rates in 2014. Thereafter it is expected that each year’s Power Purchase Deferral Account balance would be flowed through completely in the subsequent year. This flow through mechanism would ensure that customers only pay for the actual amount of power purchased.

In any event, the Company expects that the previously existing mechanism for flow through of BC Hydro rate increases and BPPA expense would be retained.

4.1.5.1 REVENUE VARIANCE DEFERRAL ACCOUNT

To the extent that Power Purchase Expense variance resulting from a difference in sales load between forecast and actual are adjusted, it is necessary to match this treatment by means of a deferral account to flow through variances in sales revenue, the majority of which are attributable to weather related load variances, customer usage rate variances and customer count load variances.

Flow through treatment of load variances is, again, included in the BC Hydro energy cost deferral accounts, and in the FEU mechanisms (Rate Stabilization Adjustment Accounts).

Table 4.1.5.1-1 below shows the load variance and Revenue variance for the years 2007 to 2011 (forecast).

Table 4.1.5.1-1 Sales Load and Revenue Variance 2007 – 2011

	2007	2008	2009	2010	2011F	Total
			Over/(Under) Approved			
Sales Load Variance (GWh)	13	-	50	(153)	25	
Sales Load Variance (%)	0.4%	-	1.6%	-4.8%	0.8%	
Sales Revenue Variance ($000s)	2,283	(41)	3,809	(12,483)	2,358	(4,074)
Sales Revenue Variance (%)	1.1%	0.0%	1.6%	-4.8%	0.8%	

In the same manner as Power Purchase Expense, the ROE sharing mechanism ensured that these variances were effectively shared equally with customers. Between 2007 and 2011, the sharing mechanism would have resulted in a net increase to revenue requirements of 50 percent of the total revenue variance, or $2.0 million. The Company believes that if load-driven variances in Power Purchase Expense are to be flowed through, then load-driven variances in revenue must also be flowed through. In addition, as the Company implements conservation rates, and continues to utilize DSM programs as an incentive for customer energy conservation, the proposed deferral mechanism will help to ensure that the extent to which conservation occurs, will not cause the Company to over or under recover its revenue requirement.

The Company proposes that revenue variances be flowed through over a period of three years, in order to smooth the effect of weather variances and the effect on revenue requirements. That is, one third of the forecast opening (January 1) deferral account balance would be applied to rates in each year.

4.1.5.2 NET IMPACT OF POWER PURCHASE AND REVENUE VARIANCES

Table 4.1.5.2 below shows the net margin (Revenue less Power Purchase Expense) variances for the period 2007 to 2011 (forecast). In total, $15.0 million in net margin would have served to reduce customer rates, compared to $7.5 million shared through the existing PBR sharing mechanism. This would have provided approximately 3.0 percent in additional rate relief to customers.

Table 4.1.5.2 Sales Load and Revenue Variance 2007 – 2010

	2007	2008	2009	2010	2011F	Total
			Over/(Under) Approved			
Sales Load Variance (GWh)	13	-	50	(153)	25	
Sales Load Variance (%)	0.4%	-	1.6%	-4.8%	0.8%	
Margin Variance ($000s)	4,914	2,487	3,977	(4,039)	7,614	14,953
Margin Variance %	3.6%	1.6%	2.4%	(2.3%)	3.9%	

4.1.6 Wheeling Expense

The Wheeling Expense forecast includes an estimate of 2011 expense based on actual results to April 30, 2011, with an estimate for May through December. The expense includes wheeling service provided by BC Hydro Transmission under the General Wheeling Agreement (GWA) and also wheeling provided by BC Hydro under its Open Access Transmission Tariff (OATT), as needed to supply the Company's loads in the Okanagan from Vernon and the interconnection at Vaseux Lake (which together are termed the Okanagan Point of Interconnection), and at Creston and Princeton. Also included are charges paid to Teck for the use of its 71 Line.

Rates under the GWA are specified in BC Hydro's Rate Schedule 21. In 2012 and 2013, GWA costs are forecast to account for all the wheeling expense except for $0.024 million of OATT and Teck wheeling expense.

Wheeling Expense is forecast to increase from $4.2 million in 2011 to $4.7 million in 2012 and $5.2 million in 2013. This is due to higher wheeling nominations in the Okanagan, increasing from 180 MW to 200 MW on October 1, 2011 and from 200 MW to 225 MW on October 1, 2012 to account for increased load growth in the region. Wheeling expense has also increased because of the general rate increase based on the forecast CPI. Annual Wheeling Expense is shown in Table 4.1.6-1 below. The calculation of Wheeling Expense for 2012 and 2013 is shown in Tables 4.1.6-2 and 4.1.6-3, respectively.

Table 4.1.6-1 Wheeling Expense

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	**Wheeling Nomination**		(MW)		
2	Okanagan	2,160	2,220	2,475	2,715
3	Creston	420	420	420	420
4	**Expense**		($000s)		
5	Vernon/Okanagan	3,550	3,723	4,233	4,732
6	Creston	450	459	468	477
7	Other	50	61	24	24
8	**Total Wheeling Expense**	**4,050**	**4,243**	**4,725**	**5,233**

Note: Minor differences due to rounding.

Table 4.1.6-2 2012 Forecast Wheeling Expense

	2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2	**Nomination (MW)**													
3	Vernon	200	200	200	200	200	200	200	200	200	225	225	225	**2,475**
4	Lambert	35	35	35	35	35	35	35	35	35	35	35	35	**420**
5	Princeton	0	0	0	0	0	0	0	0	0	0	0	0	**0**
6														
7	**Rate ($/kW/month)**													
8	Vernon	1,701	1,701	1,701	1,701	1,701	1,701	1,701	1,701	1,701	1,734	1,734	1,734	
9	Lambert	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,109	1,130	1,130	1,130	
10	Princeton	-	-	-	-	-	-	-	-	-	-	-	-	
11														
12	**Cost ($000)**													
13	Vernon	340	340	340	340	340	340	340	340	340	390	390	390	**4,233**
14	Lambert	39	39	39	39	39	39	39	39	39	40	40	40	**468**
15	Princeton	-	-	-	-	-	-	-	-	-	-	-	-	
16														
17	**Excess Wheeling Costs ($000s)**													
18	71L Wheeling Costs	1	1	1	1	1	1	1	1	1	1	1	1	**12**
19	OATT and Emerg. Wheeling Costs	1	1	1	1	1	1	1	1	1	1	1	1	**12**
20														
21	**Total Wheeling Costs ($000s)**	**381**	**381**	**381**	**381**	**381**	**381**	**381**	**381**	**381**	**432**	**432**	**432**	**4,725**

Table 4.1.6-3 2013 Forecast Wheeling Expense

	2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2	**Nomination (MW)**													
3	Vernon	225	225	225	225	225	225	225	225	225	230	230	230	**2,715**
4	Lambert	35	35	35	35	35	35	35	35	35	35	35	35	**420**
5	Princeton	0	0	0	0	0	0	0	0	0	0	0	0	**0**
6														
7	**Rate ($/kW/month)**													
8	Vernon	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,769	1,769	1,769	
9	Lambert	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,153	1,153	1,153	
10	Princeton	-	-	-	-	-	-	-	-	-	-	-	-	
11														
12	**Cost ($000s)**													
13	Vernon	390	390	390	390	390	390	390	390	390	407	407	407	**4,732**
14	Lambert	40	40	40	40	40	40	40	40	40	40	40	40	**477**
15	Princeton	-	-	-	-	-	-	-	-	-	-	-	-	
16														
17	**Excess Wheeling Costs ($000s)**													
18	71L Wheeling Costs	1	1	1	1	1	1	1	1	1	1	1	1	**12**
19	OATT and Emerg. Wheeling Costs	1	1	1	1	1	1	1	1	1	1	1	1	**12**
20														
21	**Total Wheeling Costs ($000s)**	**432**	**432**	**432**	**432**	**432**	**432**	**432**	**432**	**432**	**449**	**449**	**449**	**5,233**

4.2 WATER FEES

Water fees are assessed by the Province based on FortisBC's generation in the previous year and the rate is indexed to the BC CPI. Water fees are down in 2011 due to reduced plant entitlement use in 2010 and due to the change in water fee escalation rates, previously tied to BC Hydro rate increases, to the Consumer Price Index (CPI). This change also resulted in water fee escalation resulted in $0.303 million before tax flowing back to customers via the flow through mechanism. Water fees increase in 2012 and 2013 due to increased plant entitlement use in 2011 and 2012 respectively, as well as the increase in water fee rates from 2011 levels based on the Company's forecast of BC CPI, which is explained in Section 4.3.3.1.

Table 4.2 Water Fees

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Plant Entitlement Use (GWh) in previous year	1,585	1,527	1,604	1,600
2	Water Fees ($000s)	**9,256**	**8,977**	**9,681**	**9,853**

4.3 OPERATING AND MAINTENANCE (O&M) EXPENSE

4.3.1 Introduction

This section focuses on the O&M expenses of FortisBC. The O&M section starts with a discussion of the general highlights and business drivers, then discusses general assumptions and ends with a discussion of the business responsibilities, issues, challenges, and O&M costs of each of the Company's operating departments.

FortisBC's O&M expenditures are required to prudently operate the utility on a safe and reliable basis. The 2012 and 2013 O&M Expense forecasts have been developed in support of the Company's business objectives, ensuring that O&M funding is appropriate and prioritized to meet the needs of customers. The primary objectives of the Company include:

- delivering safe and reliable power at a reasonable cost;
- maintaining or improving customer satisfaction;
- ensuring sound financial management;

- being environmentally responsible; and
- planning for demographic and other challenges.

Annual departmental O&M budgets are prepared by the department managers through an extensive budget process. The budget process incorporates both a trended and zero-based approach where appropriate. The budgets then go through a cycle of reviews and updates, and are eventually approved by the Company's Executive and Board of Directors. The resulting Gross O&M budgets (before Capitalized Overheads) of $54.172 million and $55.794 million for 2012 and 2013 respectively reflect the required O&M funding to prudently operate the utility. The total 2012 and 2013 O&M budgets result in approximate increases over the 2011 forecast of two percent and three percent respectively over the previous year, after normalizing out 2011 resource planning costs which are classified as power purchase costs for 2012 and 2013. The reclassification of resource planning costs is further discussed in Section 4.1.2.6 Power Purchase Management Expense.

The Company notes that if the inclusion of the PPME costs in Power Purchase Expense is not approved by the Commission, the costs must be reclassified to O&M Expense.

O&M costs are budgeted for each of FortisBC's departments. These departments are:

- <u>Generation</u> – manages, operates and maintains the Lower Bonnington, Upper Bonnington, Corra Linn and South Slocan hydro electric generating plants;
- <u>Utility Operations</u> – manages, operates and maintains the transmission and distribution assets and also includes those projects that prior to Order G-195-10 were recorded as sustainment capital (right of way reclamation, pine beetle kill hazard tree removal and hot tap connection replacement);
- <u>Mandatory Reliability Standards</u> – ensures compliance with the British Columbia Mandatory Reliability Standards (BC MRS) as adopted by Commission Order G-67-09;
- <u>Cominco Facilities Charge</u> – reflects the costs of the continued shared use of Teck facilities pursuant to the Facilities Sharing Agreement between Teck and FortisBC;
- <u>Brilliant Terminal Station Lease</u> – is the cost of the continued lease of the Brilliant Terminal Station as approved by Commission Order G-2-04;
- <u>Internal Audit</u> – develops, plans and conducts audits, reviews and risk assessments, and evaluates the effectiveness and efficiency of internal controls;

- Legal and Regulatory – manages legal and regulatory activities and compliance, prudently mitigates legal exposure and maintains relationships with the BCUC, interveners, customers and other stakeholders;
- Customer Service – manages the interaction and relationships with customers including billing and customer systems, meter reading, customer contact centre, key account management, demand side management and advanced metering infrastructure;
- Community and Aboriginal Affairs – manages the Company's community relations, community investment and Aboriginal Affairs activities;
- Communication – manages the Company's corporate and customer communications including employee communications, customer communications, advertising, public education and social marketing, media relations, website, social media and community outreach initiatives;
- Human Resources – manages the Company's employee relations, compliance training, compensation and benefits and payroll activities;
- Information Technology – manages the reliable operation of the Company's information systems including software applications, data and the supporting infrastructure and telephony;
- Health, Safety and Environment – manages the Company's health, safety and environmental activities;
- Facilities Management – manages the Company's building facilities including operation and maintenance, physical security, space planning, office furniture and equipment and mailroom services;
- Finance and Accounting – manages the Company's budgeting and forecasting, financial reporting, treasury and accounting activities;
- Transportation Services – manages the Company's fleet asset management, fleet maintenance and fleet support activities;
- Supply Chain Management – manages the range of processes relating to the flow of goods and services between suppliers and end users including purchasing, warehousing, materials management, inventory control and hazardous waste management; and
- Corporate and Executive Management – captures the costs for insurance, Board of Directors, Fortis Inc. corporate services, other corporate initiatives and executive costs.

Contained in Table 4.3.1 below is a summary of the Company's O&M budgets:

Table 4.3.1 O&M Budgets

	DEPARTMENTS	2010 Actual	2011 Forecast	Labour Inflation	Other	2012 Forecast	Labour Inflation	Other	2013 Forecast
		($000s)							
1	Power Purchase Management Expense	827	927	-	-	-	-	-	-
2	Generation	2,217	2,187	64	36	2,287	176	35	2,497
3	Utility Operations	13,155	17,412	968	123	18,503	387	74	18,964
4	Mandatory Reliability Standards	-	955	153	71	1,179	8	0	1,187
5	Cominco Facility Charge	46	46	-	(0)	46	-	-	46
6	Brilliant Terminal Station	3,069	2,987	-	173	3,160	-	32	3,192
7	Internal Audit	360	348	72	(24)	396	7	(11)	393
8	Legal & Regulatory	1,451	1,502	8	9	1,520	28	0	1,548
9	Customer Service	5,975	6,412	172	152	6,737	47	22	6,806
10	Community & Aboriginal Affairs	571	594	21	59	674	(7)	22	689
11	Communications	1,067	903	(183)	203	923	11	18	952
12	Human Resources	1,638	1,789	114	(63)	1,840	(41)	75	1,874
13	Information Technology	2,824	2,815	(48)	74	2,841	(45)	49	2,846
14	Health, Safety & Environment	727	907	29	(11)	925	35	(7)	953
15	Facilities Management	3,700	3,620	67	(2)	3,685	8	23	3,716
16	Finance & Accounting	2,617	3,092	38	145	3,275	55	30	3,360
17	Transportation Services	377	766	(226)	33	573	20	(0)	593
18	Supply Chain Management	478	550	(25)	(27)	498	(3)	10	505
19	Corporate & Executive Management	5,049	6,072	15	(975)	5,112	49	513	5,674
20	**TOTAL O&M EXPENDITURE**	**46,148**	**53,885**	**1,239**	**(24)**	**54,172**	**736**	**886**	**55,794**
21	**Power Purchase Management Expense**			**199**	**85**	**1,211**	**34**	**21**	**1,266**
22	**TOTAL O&M EXPENDITURES Prior to reclassification of Resource Planning**	**46,148**	**53,885**	**1,438**	**60**	**55,383**	**770**	**907**	**57,060**

Through the PBR period, from 2007 to 2011, the Company has achieved O&M efficiencies of 10.4 percent as a result of the negotiated productivity improvement factors. After factoring out the $3.78 million that was transferred from capital to O&M Expense in 2011 as directed by Order G-195-10 concerning the Company's 2011 Capital Expenditure Plan, and those items referred to under the PBR mechanism as extraordinary O&M Expense, the O&M Expense per customer, on a real basis, has declined over the period 2007 to 2013. These efficiencies were achieved while improving or maintaining service levels. FortisBC's customer satisfaction has increased from 70 percent in 2004, when Fortis Inc. acquired the Company, to an average of 87 percent over the past three quarters.

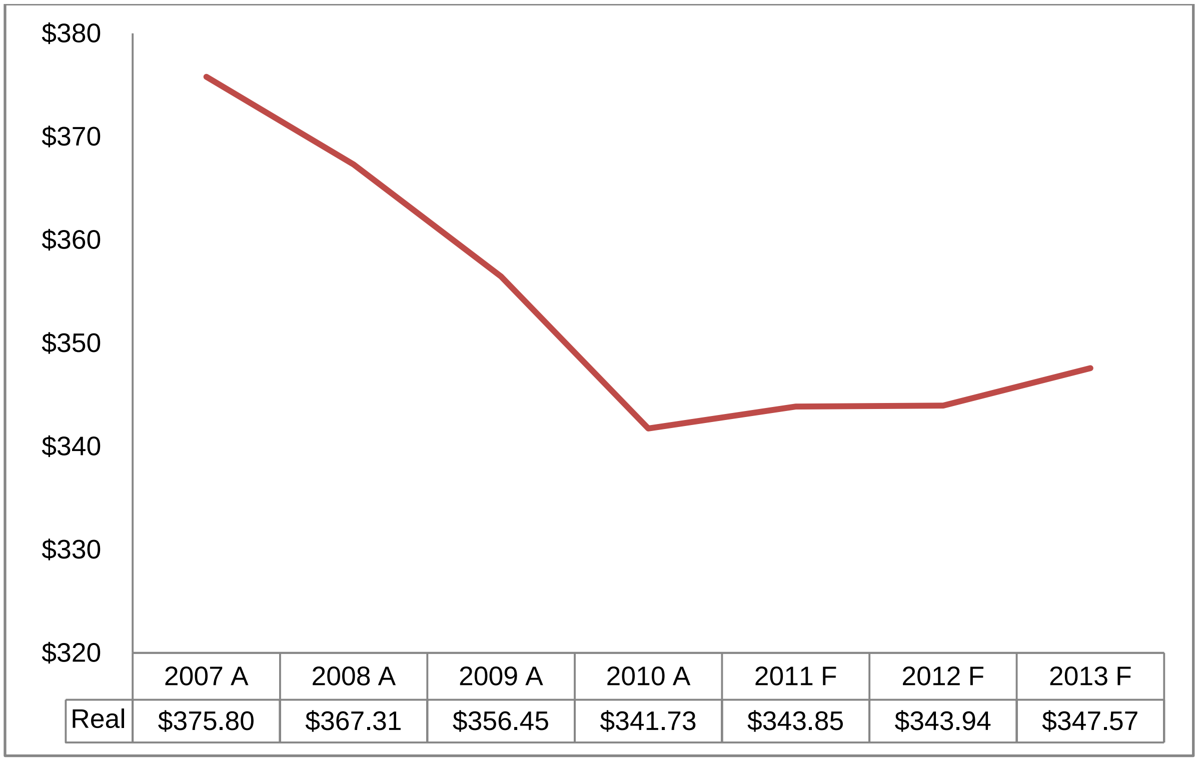
This demonstrates that FortisBC has been successful in managing its O&M expenditures to minimize its impact on customer rates. The 2012 and 2013 requested increase in O&M impacts customer rates by approximately 0.1 percent and 0.4 percent respectively. The achievements in managing O&M have been made despite substantial number of changes affecting FortisBC over this period. Some examples of these changes include:

- Changes to government policy in terms of energy use;
- Increased customer expectations;

- Increased compliance with various regulatory bodies (financial, environmental, etc.);
- Increased requirements for most segments of FortisBC operations;
- Increased First Nations expectations; and
- Inflationary pressures.

The O&M per customer, on a real basis can be seen below.

Figure 4.3.1 Base O&M per Customer



4.3.2 General Highlights and Business Drivers:

4.3.2.1 LABOUR INFLATION

The Company has three employee groups consisting of executive, exempt and unionized. The unionized employees are represented by two unions, the Canadian Office and Professional Employees Union (COPE) and the International Brotherhood of Electrical Workers Union (IBEW). For each employee group FortisBC targets a total compensation package which is at the median level of a peer group of companies. Labour and benefit inflation are primarily non-discretionary cost increases required to fund expected wage and benefit increases for the Company's employees. The total incremental funding in this category is further summarized in

Table 4.3.2.1. Labour and benefit inflation will be discussed globally for the Company rather than specifically be addressed in each departmental discussion.

In a labour market with increasing demographic challenges in certain areas, FortisBC must continually monitor and assess its Total Rewards[1] framework to ensure the Company remains competitive with other employers that have a competing need for similar skill sets. The challenge is to find a balance where the Company is able to attract and retain talented people. The guiding principle is to deliver a total compensation program that is prudent, competitive, understandable and efficient to administer. Paying competitive rates will allow FortisBC to attract the appropriate talent and help to retain employee knowledge in key areas of the Company that are critical to the future success of the business. The compensation philosophy of FortisBC is further discussed in Section 4.3.3.2.

FortisBC needs to ensure that the Total Rewards meets the broad needs of the workforce while retaining, attracting and motivating the talented individuals that FortisBC needs in order to continue to meet business goals and deliver service excellence to its customers.

The O&M labour inflation adjustments for 2007 to 2013 are summarized as follows:

[1] Total Rewards refers to all of the tools available to an employer that may be used to attract, motivate and retain employees. Total Rewards includes everything the employee perceives to be of value resulting from the employment relationship and may include:

Pay: Base Pay, Variable Pay, Long-term incentives;

Benefits: Health Care, Pension, Time Off;

Learning & Development: Training, Career Development, Performance Management, Tuition Support

Work Environment: Leadership, Values, Work/Life Balance, Organizational Climate

Table 4.3.2.1 Labour Inflation (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
2.0	**Pay Increases**							
2.1	COPE(1)	2.5%	2.5%	2.5%	3.5%	*	*	*
2.2	IBEW(2)	1.5%	3.0%	3.0%	3.0%	4.0%	5.0%	*
2.3	Exempt	3.0%	4.0%	3.5%	4.0%	3.0%	3.0%	3.0%

**Subject to Negotiation: filed in confidence.*

(1) The COPE contract expired on January 31, 2011 and is currently under negotiation.

(2) The IBEW contract expires on January 31, 2013.

Having a stable and productive unionized workforce is important to FortisBC's ability to deliver on its objectives and priorities. The COPE collective bargaining agreement expired on January 31, 2011, while the IBEW agreement expires January 31, 2013. Although the Company has started initial discussions with COPE, formal negotiations have not commenced. For this reason the labour inflation component of this Application is being filed in confidence.

Wage increases for IBEW were negotiated during the last round of bargaining at 4 percent for 2011 and 5 percent for 2012. Consistent with usual practice, standard length of service-related step increases for unionized staff have also been included in labour inflation. Labour inflation for 2012 and 2013 is forecast at 3 percent annually for non-union (executive and exempt) employees. The 3 percent increase for non-union labour inflation is the increase required to achieve FortisBC's compensation philosophy of establishing compensation at the median of its defined peer group.

4.3.2.2 CUSTOMER AND STAKEHOLDER EXPECTATIONS

The primary ways that the Company obtains feedback from its customers is through customer surveys and public workshops and information sessions.

The Company surveys its residential and commercial customers four times per year using a third party polling company to conduct telephone surveys with approximately 350 randomly selected customers. Customer ratings of various components of company services are used to calculate an overall customer satisfaction metric called the Customer Service Index (CSI). In this survey, FortisBC also collects a variety of information regarding customer priorities.

As part of its regulatory processes, The Company often hosts public workshops and information sessions in which it gathers customer feedback about specific projects and regulatory applications. The results of these workshops and sessions are included in the respective applications.

Customer Surveys

When asked to rank issues in order of importance, over 80 percent of customers identified reliability or cost as most important in the 2010 surveys. The number one concern for over 50 percent of respondents is the "reliability and dependability of service". Reliability has been steadily improving and FortisBC has maintained a good and consistent CSI score since early 2007, which is indicative that the Company is meeting the expectations of its customers and that they value the service it is providing.

4.3.2.3 DEMOGRAPHICS

Overview of the Demographic Risk:

The demographic challenges presented by FortisBC's aging workforce require focused effort to proactively recruit, train and develop, transition, and manage overall changes to the composition of the workforce in the coming years. Shifting workforce demographics have been a well-known global reality for some time and continue to be a source of concern for governments and businesses alike. The initial wave of baby boomers has reached retirement age and the number of workers in British Columbia retiring each year is expected to increase from 56,000 to over 62,000 over the next decade[2]. As this scenario unfolds, the long predicted labour shortages, particularly within the skilled and professional trades, will begin to materialize. The combination of an aging population, declining birth rates, and continued economic growth will create significant pressure on businesses and available labour supply:

> *"As a result of economic growth, employment in British Columbia is expected to grow by an average of 1.8 percent each year through to 2019, creating a total of 450,000 new jobs. Approximately 676,000 additional jobs will become vacant due to retirements. In total, there will be an expected 1,126,000 job openings over the next decade. There are about 650,000 young people in our education system*

[2] Skills for Growth: British Columbia's Labour Market Strategy to 2010; Ministry of Regional and Economic Skills Development, Page 5

today which means that the growth in job openings is expected to outpace the number of workers." [3]

In 2008, the Electricity Sector Council, with the support of Human Resources and Social Development Canada (HRSDC) published "Powering Up the Future - 2008 Labour Market Information Study", a comprehensive study of the Canadian electricity industry. The report characterizes the Canadian electricity industry as being "on the edge of a perfect storm" with an aging workforce, aging and inadequate infrastructure, and increasing demand from domestic and export markets.

Like many other organizations faced with an aging workforce and a shrinking labour market, FortisBC faces the challenge of having approximately half of its current workforce eligible to retire in the next five years. In fact, between 2011 and 2016, 269 FortisBC employees, or 49 percent of the employee population of 549, are eligible to retire with pensions. 155 or 28 percent are eligible to retire with an unreduced pension. The following graph and table provide the number of employees eligible to retire with an unreduced pension by organizational division over the next five years. This information is displayed in Table 4.3.2.3-1 below.

[3] Ibid

Figure 4.3.2.3-1 Employees Eligible to Retire Within Five Years

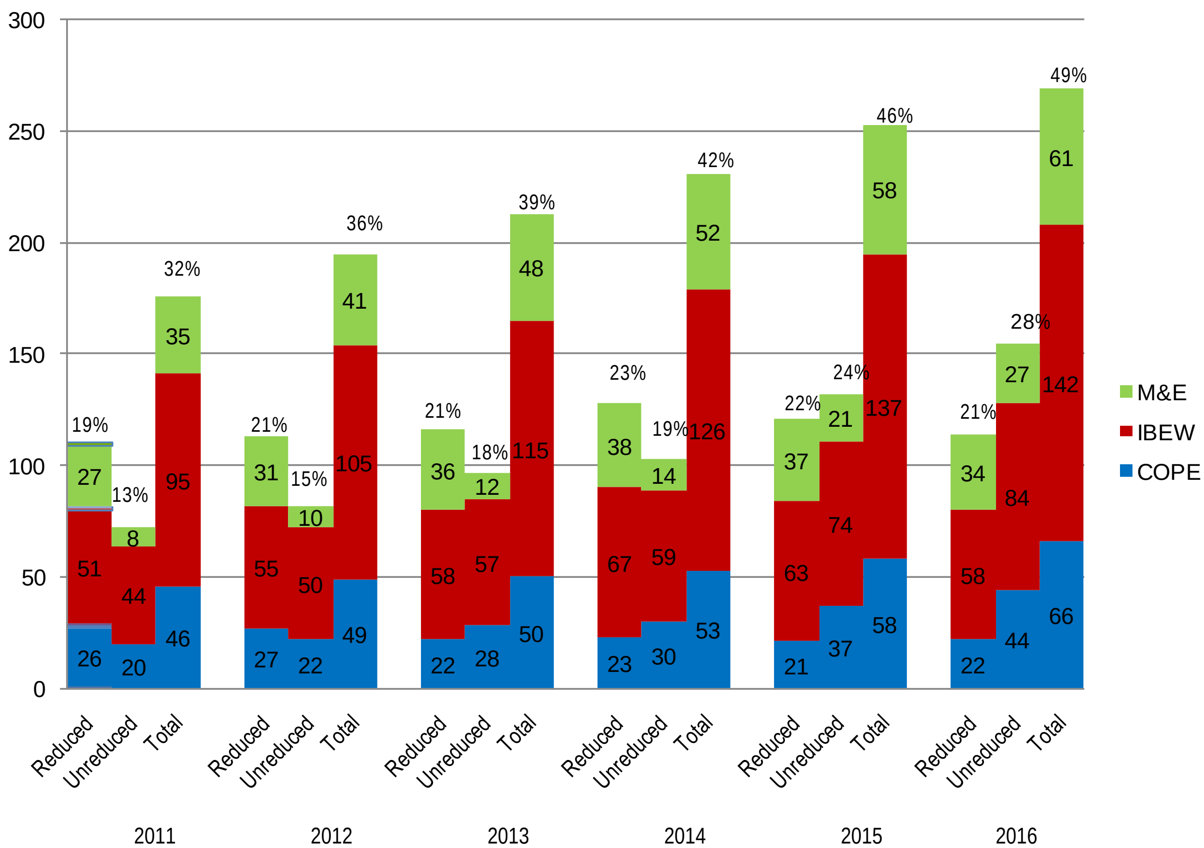


Table 4.3.2.3-1 Employees Eligible to Retire Within Five Years

	2011			2012			2013			2014			2015			2016		
	Reduced	Unreduced	Total	Reduced	Unreduced	Total	Reduced	Unreduced	Total	Reduced	Unreduced	Total	Reduced	Unreduced	Total	Reduced	Unreduced	Total
COPE	26	20	46	27	22	49	22	28	50	23	30	53	21	37	58	22	44	66
IBEW	51	44	95	55	50	105	58	57	115	67	59	126	63	74	137	58	84	142
M&E	27	8	35	31	10	41	36	12	48	38	14	52	37	21	58	34	27	61

The following Table 4.3.2.3-2 provides the percentage of employees eligible to retire with an unreduced pension by department over the next five years.

Table 4.3.2.3-2 Retirement Risk Varies by Department

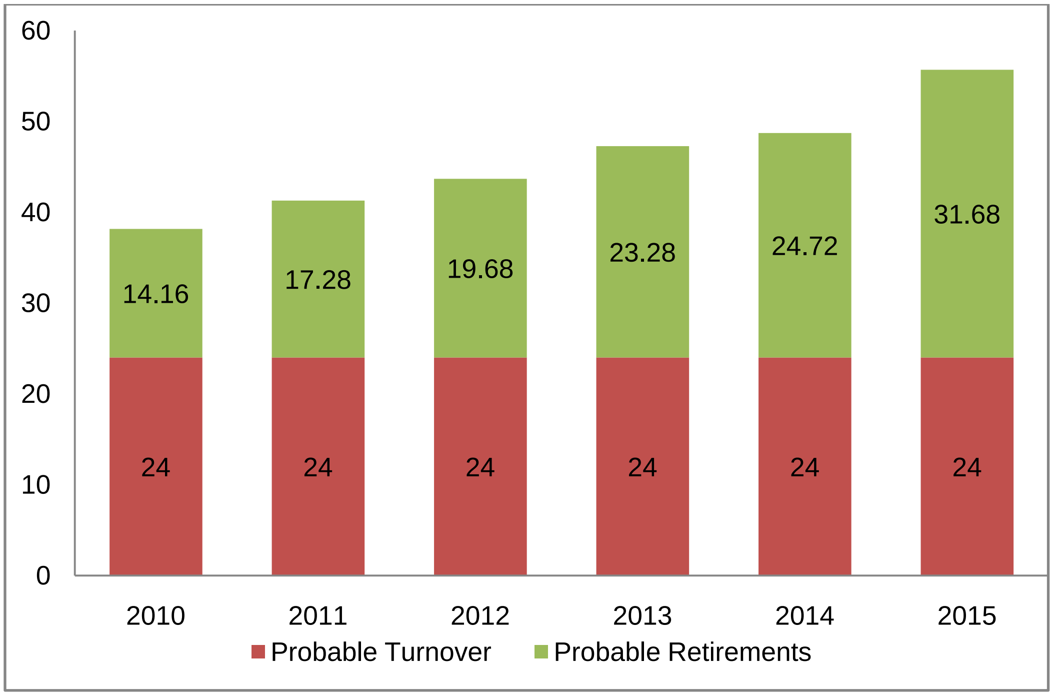
	2010	2011	2011-2012	2011-2013	2011-2014	2011-2015	2011-2016
Corporate Services	9	11	14	14	16	22	26
Engineering	4	4	4	8	9	9	11
Finance	7	8	9	10	10	11	14
Generation	10	16	16	20	20	29	36
Transmission and Distribution	29	33	38	44	47	59	66
Other	0	0	1	1	1	2	2
Total	59	72	82	97	103	132	155

33 of the 72 employees eligible to retire with an unreduced pension in 2011 are in the Transmission and Distribution (T&D) department. The positions that require focus are Power Line Technicians (PLT), Meter Technicians, Communication, Protection and Control Technicians and Power System Dispatchers.

Approximately 30 percent of T&D managers are eligible to retire with reduced or unreduced pensions by 2013. These workforce challenges continue to create demand for field training as well as management and leadership development.

It is difficult to forecast the actual number of employees who will exercise their option to retire when they become eligible to do so. Many factors influence the decision including age, health, financial status, and family status. Between 2006 and 2010, the average number of employees who actually retired versus the number who were eligible to retire with an unreduced pension was 24 percent. Based on this trend, Figure 4.3.2.3-3 below shows it is likely that a minimum of 17 employees will exercise their option to retire in 2011, a number that grows cumulatively to 20 by 2012 and 23 in 2013 if retirement is deferred.

Figure 4.3.2.3-3 Combined Retirement and Turnover Risk



In addition to the retirement risk, employee turnover also has the potential to create additional risk and cost (lost productivity, recruiting costs, training, and overtime costs for replacement workers) with estimates typically ranging from 30 percent of annual wages for hourly employees up to 100 percent and 150 percent for management and senior management positions. Between 2008 and 2010, average Full Time Regular voluntary turnover (not including retirements) averaged about 4.5 percent which, generally speaking, is in line with industry statistics. Table 4.3.2.3-2 below compares FortisBC's turnover rate with the Conference Board of Canada's Annual Compensation Planning Outlook reported voluntary turnover rates for comparable sectors:

Table 4.3.2.3-2 Comparable Sector Voluntary Turnover Rates

	2008	2009	2010
		(%)	
All Sectors	9.7	8.2	6.1
Transportation and Utilities	7.3	6.1	4.5
Oil and Gas	9.4	6.5	3.9
FortisBC	5.9	3.1	4.6

Managing the Demographic Risk:

FortisBC has been proactive in mitigating the known demographic risks through its workforce strategies.

Between 2008 and 2010, 181 new employees were recruited, which includes all levels of positions within FortisBC. In 2008, the Company responded to the market shortage of PLTs, by implementing Interim Market wage adjustments and running additional apprenticeship programs. At the end of 2010, there were seven active apprentices in the PLT apprenticeship program. FortisBC's workforce strategy during the capital expansion program was to enhance staffing levels in key trades areas, specifically PLTs. The non-union employee group also increased in numbers to support the capital program.

FortisBC is a founding sponsor of the British Columbia Bright Futures initiative lead by the Electricity Sector Council (ESC). The objective of the Bright Futures program is to generate workforce supply by creating interest among high school students about careers within the utility sector. The Program also supports educational programs geared towards the electrical industry.

In its "Vision 2030" draft report, the Canadian Electricity Association (CEA) highlighted the need for further investment in training and employee development:

> *"In addition to the need to engage and educate the public at large, another important element of education policy is to ensure that the human resources and training needs of the sector are met. Utility work forces are aging; much of this workforce will retire by 2030. In addition, there has been relatively limited investment in the sector in the last thirty years. As a result, there are a limited number of skilled workers available to build the infrastructure that the sector requires. Therefore, programs need to be developed and expanded to train a new generation of engineers and skilled laborers. When considering the electric utility sector, prospective employees will assess the opportunities offered. As such it is important that the exciting opportunities offered by the sector are known and understood." (Canadian Electricity Association, Vision 2030, January 2011 draft, page 19)*

Initiatives being undertaken to mitigate these risks include:

- Review and manage total compensation plans to ensure FortisBC remains competitive with market;

- Continue to support industry initiatives that promote/raise awareness about careers in electricity sector;
- Develop and execute succession plans and workforce plans where appropriate;
- Develop recruitment and retention strategies for difficult to fill positions. Positions of focus remain: Meter Technicians, Communication Protection and Control Technologists, Power Line Technicians and System Power Dispatchers; and
- Provide management and leadership training to ensure there is sufficient skilled management and leadership capacity to meet business needs;

Investing in education is an important element in developing FortisBC's future workforce. In 2007, in partnership with British Columbia Transmission Corporation (BCTC, now BC Hydro), BC Hydro and the Ministry of Education, FortisBC became a founding sponsor of the Power Engineering program offered at the University of British Columbia (UBC).

The ESC reports that regionally, British Columbia saw the number of enrolments in engineering programs rise 14 percent compared with 3 percent nationally. This increase in engineering enrolments will provide skilled resources in short supply.

Attracting electrical engineers to the electricity sector has been a challenge. To address this gap FortisBC developed an Engineer-in-Training (EIT) program designed to develop and strengthen its engineering pool. The EIT program brings new graduates into the Company and operations while they work towards accreditation as professional engineers in the province of British Columbia. In 2010, in partnership with Fortis Alberta, the EIT program expanded to include rotation between the companies. EITs in the program are the principle candidate pool for future engineering vacancies. The program has been a successful component of the Company's overall workforce strategy.

As part of the Company's commitment to support the electrical industry, more than 70 scholarships were offered to students pursuing post-secondary education in electrical engineering or electrical trades. Annually, third-year electrical engineering students are awarded the FortisBC Scholarship in Engineering at the University of British Columbia Okanagan (UBCO).

Between 2008 and 2010, 35 co-op students were hired by the Company. The co-op program supports student school programming while providing students with work experience in the utility sector. Co-op students become known candidates for future opportunities in the

Company; traditionally the best co-op students are retained post graduation. Co-op students have been sponsored in Engineering, Drafting, Office Administration, Human Resources, Finance and Accounting, and Information Technology (IT). Scholarships and co-op programs provide opportunities for FortisBC to attract the "best and brightest" talent at an early age, provide valuable work experience, assess performance, and offer "retainers" for employment once the students have completed their studies.

Between 2008 and 2010 FortisBC welcomed 40 grade 9 students in both the Kootenay and Okanagan regions to participate in the annual Take Our Kids to Work Day. The program illustrates the importance of education, skills development and training while giving students, children and relatives of employees the opportunity to experience the world of work, and learn about career options at FortisBC.

Another component of FortisBC's workforce strategy was the creation of a Supervisory Skills Development Program in 2009. The Program is a key component of the company's overall workforce strategy in the upcoming years. The intent of the program is to develop the Company's own leaders to fill manager and supervisor vacancies. Table 4.3.2.3-3 below provides a summary of the type and volume of training delivered between 2006 and 2010:

Table 4.3.2.3-3 Training Delivered (2006-2010)

		2006	2007	2008	2009	2010
1	SAFETY/COMPLIANCE TRAINING					
2	Total Number of Courses	142	167	147	299	267
3	Number of Classes (delivered)	459	507	777	618	647
4	Total Number of Courses Delivered	2,625	3,671	6,498	4,735	5,448
5	EMPLOYEE DEVELOPMENT AND LEADERSHIP MODULES					
6	Total Number of Courses	11	7	10	65	58
7	Number of Classes (delivered)	18	13	13	104	85
8	Total Number of Courses Delivered	18	164	342	853	365
9	TOTALS					
10	Total Number of Courses	153	174	157	364	325
11	Number of Classes (delivered)	477	520	790	722	732
12	Total Number of Courses Delivered	2,643	3,835	6,840	5,588	5,813

In summary, FortisBC must continue to focus its efforts on the retention, attraction, and development of employees in order to effectively meet the evolving needs of customers over the next two years. The demographic challenge facing employers across the country is very real.

Businesses must develop different strategies and investment priorities to manage these risks, and for FortisBC the demographic challenge is no less daunting to ensure the needs and expectations of customers continue to be met.

4.3.3 General Assumptions

4.3.3.1 INFLATION

A chief measure for general economic inflation is CPI, which measures changes in the price level of consumer goods and services purchased by households. The CPI forecast for 2012 and 2013 is calculated by using the average CPI forecasts from four different institutions; these include the BC Ministry of Finance, the Conference Board of Canada, the Toronto Dominion Bank and the Bank of Montreal. The CPI forecast is updated monthly with any new information or updated forecasts. Currently the forecast for 2012 for CPI is 2.2 percent followed by 1.9 percent in 2013.

Labour inflation is discussed in section 4.3.2.1.

4.3.3.2 EMPLOYEE COMPENSATION

For the purposes of compensation and benefits, FortisBC's workforce is separated into three primary groups:

- Executives;
- Non-Union employees; and
- Unionized employees represented by the IBEW or COPE.

While the details of the compensation and benefits programs vary between these three groups, the Company applies the same philosophy and approach to compensation and benefits for all employees. This approach includes a total compensation package that rewards employees with competitive base salaries and wages, incentive compensation, benefits, and paid time off.

The key objectives of the compensation and benefits program are to align FortisBC to the median of a group of companies.

- Retain and motivate a qualified, diverse workforce by recognizing and rewarding achievement, contribution, and excellence;
- Attract a qualified workforce through a competitive compensation program;

- Reward by providing a consistently applied compensation program that meets the needs of a diverse workforce; and
- Promote continuous learning, leadership development and training.

Executive Employees

The Company's executive compensation program is designed to provide competitive levels of compensation, a significant portion of which is dependent upon individual and corporate performance. The compensation package is designed to retain and attract qualified and experienced executives as well as align the compensation level of each executive to that executive's level of responsibility. The objectives of the total compensation package are to recognize market pay, and acknowledge competencies and skills of individuals. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance objectives and focus on key activities and achievements critical to the ongoing success of FortisBC. Long-term incentive plans focus executives on sustained customer value creation.

The Company's executive compensation program involves four main elements (base pay, short term and long term incentive pay, and benefits), which comprise a Total Rewards package. All of these factors support the needs of the business and its customers, and each element contributes to delivering successfully on both short and longer term objectives.

As a general policy, FortisBC establishes base and incentive compensation targets so as to compensate executives at a median level of a broad reference group of Canadian commercial industrial companies.

With the exception of the pension plan, benefits provided to the executives are based on the benefit program for Non-Union employees. The RRSP (Registered Retirement Savings Plan) arrangement provides for equal contributions of 6.5 percent of salary by both the employee and employer up to the Canada Revenue Agency (CRA) RRSP maximum limit. The Company makes notional contributions in excess of the RRSP maximum limit equal to 13 percent of earnings to a Supplemental Executive Retirement Plan (SERP).

Non-union Employees

As a general policy, FortisBC establishes base and incentive compensation targets at the median level of a peer group of companies. The peer group is representative of a commercial/industrial group with an emphasis on natural resources and utilities. Pay increases and incentive for all employees are linked to individual and Company performance. FortisBC also offers an employee benefits program for Non-Union employees comprised of pensions, health and welfare benefits, and other work-related benefits. The employee benefits program is targeted to be competitive at the median level of an established group of comparator companies.

Unionized Employees

In 2006 FortisBC reached a five year labour agreement with COPE and in 2009 reached a four year labour agreement with IBEW. IBEW wage increases for 2011 and 2012 are 4 percent and 5 percent respectively whereas COPE wage increases are subject to the current round of collective bargaining and have yet to be determined. The last COPE agreement introduced greater flexibility in benefits by implementing a flexible benefits plan.

4.3.4 Department Operating and Maintenance Budgets

Following the consolidated O&M in Table 4.3.4 below, is a detailed department level discussion of business responsibilities and budgets.

Table 4.3.4 Consolidated O&M Cost Summary

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	561	564	560	535	552	557	558
		($000s)						
2.0	**Expenses**							
2.1	Labour	26,998	29,446	30,083	30,062	32,878	33,334	34,071
2.2	Non Labour	16,003	15,279	15,935	16,086	21,007	20,838	21,723
TOTAL O&M EXPENDITURE:		43,001	44,725	46,017	46,148	53,885	54,172	55,794

4.3.4.1 GENERATION:

Business Responsibilities:

The Generation department at FortisBC manages, operates and maintains the Company's four generating stations along the Kootenay River, forming an integral part of the power supply system. These facilities include the Lower Bonnington Dam which was originally constructed in 1897 and upgraded in 1924, the Upper Bonnington Dam constructed in 1907 and extended to incorporate an additional two units in 1940, the South Slocan Dam constructed in 1924 and the Corra Linn Dam which was constructed in 1932. In total, there are 15 units ranging in size from

5 MW to 23 MW with an installed capacity of 223 MW and a yearly entitlement of 1,591 GWh. Due to the ULE program, it is expected that by 2012, the installed capacity of the 15 units will increase to 227 MW with annual entitlement energy of 1,612 GWh.

In addition to the operations and maintenance of these four facilities, the department also manages under various contracts, an additional 900 MW of generation in four additional facilities owned by CPC and Teck. Where the provision of services for these contracts is performed by a non-regulated affiliate, the services are governed by the FortisBC Code of Conduct and Transfer Pricing Policy (COC and TPP) which was recently reviewed and approved by the Commission via Order G-5-10A.

The department employs approximately 100 employees throughout a typical year comprised of approximately 65 full time and 30-35 temporary employees dependent on the type of work and the timing of such work. In addition to skilled trades, the full time employees in the Generation department include management, engineering, planning, project management and safety and environment staff.

Business Issues / Challenges:

Generation faces a number of issues of note as it moves into 2012 and 2013, which are listed in greater detail below:

1. Completion of the Upgrade and Life Extension Program – During the ULE program, the Generation department was able to defer or eliminate certain routine operating and maintenance tasks in the facility in which the ULE project was taking place. For example, annual inspections could be cancelled for the unit under construction, and since the plants were staffed full time, other routine tasks could be deferred until completion of the project;

2. With the completion of the ULE program, the Company will return to its full maintenance program at all facilities, resulting in an increase in planned routine maintenance activities over previous years;

3. An additional consideration that will have an impact on the Generation department's O&M budget is related to the reintroduction of non-routine maintenance projects beyond the ULE program. Since the commencement of the ULE program, the non-routine maintenance tasks which were completed prior to the start of the ULE program were deferred as extensive work was being conducted in the facilities and many systems were being rebuilt. With the completion of this program, some of the rebuilt units are

approaching 12 years in age and are due for maintenance activities which are usually scheduled for intervals of 10 or 15 years. For example, unit overhauls are typically scheduled to occur on a 10 year or 80,000 hour interval. These overhauls are essentially an in-depth inspection and include activities such as removal of the rotor, cleaning of the rotor and stator, thorough electrical inspection and mechanical and electrical component maintenance which are only possible when the rotor has been removed. Other non-routine activities include turbine cavitation welding, hoist overhauls, auxiliary component overhauls and Dam Safety activities such as Dam Safety Reviews;

4. Species at Risk Act (SARA) – Within the reach of the Kootenay River, where the FortisBC facilities are located, there are two new species of fish which could potentially be listed under the SARA (Umatilla Dace and White Sculpin). The impact of the listing of a species can have has been seen at the Brilliant, Brilliant Expansion, Arrow Lakes and Waneta facilities with the listing of the white sturgeon. The experience at these facilities is that increased observation and changes to operating procedures to include consideration of the listed species can result in increased operating costs. It is unknown at this time whether the Umtilla Dace or White Sculpin will be listed, but there may be a requirement to conduct fish stranding studies and modify operating plans at the existing facilities if these fish do become listed under SARA legislation;

5. Changes to Workplace Health and Safety requirements – Recent changes to legislation targeted at improving workplace safety have had an impact on operating costs over the past five years. For instance, changes to confined space legislation and working alone legislation has resulted in a safer workplace but has also required modifications to work plans to include additional staff to meet the new requirements. The recognition of silica dust (from concrete coring, drilling, etc.) has resulted in the requirement for new equipment and additional time added to routine type work to manage the risks associated with this substance. As new information becomes available, legislation and accepted practices are evolving and FortisBC is committed to ensuring a safe work environment. There is the potential that these changes can have an impact on operating costs.

Table 4.3.4.1 below shows a summary of the Generation department's O&M costs for the years 2007 through 2013.

Table 4.3.4.1 Generation O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	103	97	98	96	97	97	97
		($000's)						
2.0	**Expenses**							
2.1	Labour	1,155	1,344	1,235	1,329	1,633	1,697	1,873
2.2	Non Labour	753	550	917	888	554	590	624
TOTAL O&M EXPENDITURE:		1,908	1,894	2,152	2,217	2,187	2,287	2,497

Analysis of Forecast O&M Expenditure and Cost Drivers

Generation O&M expense consists of the costs to operate and maintain the equipment at each of the four generating plants. The largest percentage of this expense is labour and contracted labour.

Over the past five years labour costs have fluctuated as a result of the unit inspection schedule and corrective maintenance projects. The schedule of unit inspection outages changes from year to year due in part to the ULE program, as during the year in which a unit is upgraded no O&M costs are realized on the unit itself and on some ancillary equipment. With the conclusion of the ULE program, these fluctuations in maintenance activities and costs are expected to stabilize.

Over the period under consideration, corrective maintenance projects have also caused fluctuation in labour costs. For example, contracted labour costs and insurance recoveries were recognized in 2007 as a result of the 2006 Lower Bonnington Unit 2 Transformer failure. During the 2009 unit inspection for Upper Bonnington Unit 5, cracks in the turbine were found that required immediate welding repair. Due to turbine cavitation on Unit 6 a weld repair was required in 2007 and 2009 and is expected to occur every two years with the next scheduled in 2011 and 2013. In 2008 the Company also needed to perform corrective maintenance projects which increased labour and materials costs, such as valve failures in the Corra Linn Unit 2 and Unit 3 governors and impellor and piping failures in the Upper Bonnington dewatering systems as a result of the age of this equipment. Seasonally dependent activities also cause fluctuations in labour and contracted labour costs for snow plowing, trash rack cleaning and forebay debris removal. During years of increased snow pack levels these costs increase over average years.

As discussed previously, changes in Safety and Environmental regulations have driven cost increases over the past five years as well. Specifically, changes to confined space regulations and regulations concerned with working alone have required modifications to job planning resulting in increased monitoring when working in confined space areas, as well as changes in the Company's dewatering and lock out procedures. Primarily, these changes have resulted in additional labour requirements to complete tasks in the plants. From an environmental perspective, increasing concern for species at risk has required additional fish stranding monitoring during maintenance activities which require raising or lowering forebay and tailrace elevations.

Analysis of Historical Trends and Forecast Outlook

Operating and maintenance costs will see year over year increases in 2012 and 2013 primarily as a result of increased maintenance activities related to the end of the ULE program and the schedule of non-routine maintenance tasks.

Plant labour is forecast to increase from 2011 to 2013 by approximately $0.24 million primarily as a result of labour increases and increased routine and non-routine maintenance work. Non routine work scheduled for 2012 and 2013 include the following:

- Oil water separator inspections at all plants in 2012;
- Upper Bonnington Unit 6 turbine cavitation repairs in 2013; and
- Corra Linn spill gate gantry hoist overhaul in 2013.

Non-labour costs include primarily contracted labour and material costs. Generation has managed to reduce its overall non-labour costs since 2007 and projects them to be relatively stable over the forecast period.

Management of Cost and Efficiency

In 2010, FortisBC undertook a maintenance rationalization project which focused on maintaining existing reliability at the facilities in an efficient and productive manner while addressing the maintenance needs of the new equipment installed under the ULE program. A detailed review of each routine repetitive job task was conducted to ensure all reliability, safety, regulatory and environmental aspects were addressed, as well as the appropriateness of its maintenance interval. In addition, the project served as an initial step away from a strictly time based maintenance system towards a condition based maintenance approach. In particular, a focus was placed on the new electrical equipment installed to ensure that the time interval between maintenance cycles was consistent with current industry practice.

As a result of this project, the overall budgeted labour hours for planned routine repetitive maintenance tasks at the river plants was reduced by nearly 10 percent for 2011 with no projected impact to the existing reliability statistics. This reduction in planned routine repetitive maintenance tasks helped offset the additional costs expected in future years for the introduction of non-routine maintenance and planned maintenance from ULE projects as discussed above.

In anticipation of the transition from a capital focused group to an operations focus, Generation has reorganized its workforce into Operations and Major Maintenance. By providing a workforce focused on day to day operations, the Company expects to realize ongoing benefits through increased familiarity with the equipment and continual refinement of the maintenance tasks. The Major Maintenance group is structured to provide technical expertise and assist operations in performing capital projects and during routine maintenance shutdowns, as well as provide effective support to the various third party clients. As part of the Operations group, the Company has introduced an operator role which is aligned with existing utility practice and provides employees dedicated to operating and maintenance functions with the appropriate level of training and experience required to perform their jobs.

Moving through 2012 and 2013 the Company will continue to refine its maintenance program through the development of a more condition based maintenance approach. In 2011, additional monitoring equipment is being installed at South Slocan to permit the Company to collect and monitor condition data of equipment installed during the ULE program. Over time, this monitoring will permit the Company to further rationalize its maintenance activities by conducting maintenance on equipment based on actual need rather than on a time based interval. Benefits of this approach are expected to be increased intervals between maintenance shutdowns and increased capability to perform remote operations and diagnostics of issues in the plants.

4.3.4.2 UTILITY OPERATIONS

Business Responsibilities:

The Utility Operations department is responsible for the safe and reliable delivery of electricity to customers. The business area's primary responsibility is to safely keep the lights on. Activities include:

- Monitoring and control of the transmission and distribution system by the System Control Centre;
- Maintaining accurate mapping data of high-voltage electric facilities in the Geographic Information System (GIS);
- Engineering support for operational activities such as post-fault analysis and equipment failure investigations;
- Development and maintenance of engineering standards for equipment and construction;
- Planning, Engineering and Operations participation in inter-utility technical groups such as the Western Electricity Coordinating Council (WECC); the Northwest Power Pool (NWPP) and the Centre for Energy Advancement through Technological Innovations (CEATI);
- Predictive and corrective maintenance of substations;
- Patrolling the transmission and distribution lines;
- Performing minor maintenance and responding to outages on transmission and distribution lines;
- Vegetation management along distribution and transmission right of ways; and
- Connecting/reconnecting customers (not requiring capital construction).

Business Issues / Challenges:

As discussed in Section 4.3.2.3, FortisBC, along with other utilities throughout the industry, face the challenge of an aging workforce in the utility trades.

In the next five years, 269 FortisBC employees, or 49 percent of the employee population are eligible to retire with pensions. Of the 157 employees who work for the Network Operations department within Utility Operations, 59 will be eligible to retire with an unreduced pension by 2015 and 66 by 2016.

In the last few years the Company had found it difficult to attract and retain skilled journeyman PLTs and system controllers due to the high demand for this workforce. Similar issues have been encountered when recruiting for technical and engineering staff. Going forward, the Company will continue to actively try to recruit skilled workers into these positions and operational budgets will increase marginally over time to accommodate training in these new roles, as shown in Table 4.3.4.2 below.

Table 4.3.4.2 Utility Operations O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	Full Time Equivalents	282	273	258	229	237	248	250
					($000s)			
2.0	Expenses							
2.1	Labour	9,286	9,906	9,650	10,136	10,619	11,587	11,974
2.2	Non Labour	3,369	2,950	3,450	3,019	6,793	6,916	6,990
TOTAL O&M EXPENDITURE:		12,655	12,856	13,100	13,155	17,412	18,503	18,964

Analysis of Forecast O&M Expenditure and Cost Drivers

The Commission's decision on the Company's 2011 Capital Expenditure Plan (Order G-195-10) directed that certain capital expenditures (totalling $3.78 million) were more appropriately classified as operating expenses. These expenditures have been included in the 2012-13 operational budgets and relate to:

- Right-of-way reclamation (transmission and distribution);
- Pine beetle kill hazard tree removal (transmission and distribution); and
- Hot tap connector replacement.

Line Maintenance

Upgrades of both the transmission and distribution network that have been completed over the last five years along with proposed upgrades as outlined in the 2012 Long Term Capital Plan will mitigate upward cost pressures over time. The upgrades will also help improve customer reliability and reduce safety concerns.

Hot tap connector replacements represent an increase to line maintenance. Hot tap connector replacement involves the removal of hot tap connectors that are connected directly to the primary line and the installation of a device called a stirrup to provide a location to which the hot tap connector can be safely attached. This initiative addresses employee and public safety, and reliability issues associated with conductor burn off caused by deteriorated hot tap connectors.

Vegetation Management

Brushing is a significant component of transmission and distribution line maintenance expenditures. FortisBC takes an integrated approach to minimize costs, maximize reliability and reduce public safety hazards. The Company continues to improve its vegetation management program, focusing on controlling tree growth under or near power lines to ensure adequate clearances. This minimizes public and worker safety hazards, tree-related fires and the occurrence of customer outages. Regular surveys are conducted to determine the physical location of hazard trees and general brush clearance locations. Wherever possible, vegetation that could grow or fall into FortisBC lines is removed or, where removal is not possible, problem vegetation is dealt with using proven arboricultural methods. The Company adapts its brushing program annually with consideration of cycle times, seasonal weather anomalies (fire season) and permit requirements.

In 2007 the Company acquired Princeton Light and Power (PLP) resulting in an addition of 325 line kilometres. Excluding the addition of the PLP distribution circuits, infrastructure expansion occurs at an average of 72 km per year, or a rate of 1.1 percent. Budget forecasts for 2012-2013 have been submitted based on the increased line kilometres requiring maintenance.

Right-of-way maintenance O&M budgets will also increase in 2011 and the budget for 2012-2013 further reflects the addition of the right of way reclamation and pine beetle kill hazard tree removal programs for both transmission and distribution.

Substation Maintenance

Substations contain power transformers, breakers and ancillary equipment that control the supply of electricity to customers. This equipment is energized at high voltages, so safety measures to protect the public and workers are essential. Substation expenses include the costs of the operation and maintenance of the Company's substations, including the cost of materials and supplies incurred in connection with the inspection and maintenance of substation equipment.

Preventative maintenance is tracked using an industry standard Computerized Maintenance Management System (CMMS) which triggers maintenance tasks through time and operation intervals consistent with industry standards. The system is further being used to generate corrective maintenance work, and tasks and repair orders have been based on four year historical averages.

Maintenance expenditures for 2012 and 2013 have increased over previous years based on a historical workload and a task driven budget through the CMMS.

4.3.4.3 MANDATORY RELIABILITY STANDARDS

Business Responsibilities

On June 4, 2009 the Commission, by Order G-67-09, adopted the British Columbia Mandatory Reliability Standards (BC MRS). These standards are substantially in accordance with those previously developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). In its Order, the Commission also directed affected BC entities to file by December 31, 2009 mitigation plans outlining steps and timelines to bring themselves into compliance with the applicable reliability standards. Order G-67-09 also set out an expected date of compliance of November 1, 2010. Order G-27-10 extended the filing date for the mitigation plans to June 30, 2010.

FortisBC is responsible for ensuring that the Company becomes compliant, and maintains that compliance with the applicable standards. FortisBC has reviewed the requirements for the standards adopted and filed mitigation plans to become compliant. Ongoing effort is required to remain within auditable compliance with all standards and to evaluate the impacts and implement changes to existing and new standards.

Business Issues / Challenges

BC MRS are relatively new to all entities in the province. Previously, FortisBC was a voluntary participant in the WECC Reliability Management System (RMS). The RMS had a very limited scope compared to the BC MRS and focused primarily on operational concerns. Thus, the transition from the WECC RMS to the BC MRS represented a significant step-change in required internal processes, controls and infrastructure. Development of processes and procedures amongst the entities in British Columbia, WECC, and the BCUC is evolving and will continue to do so. In addition, there are ongoing changes to existing standards and potential adoption of new standards. Impacts of changes to FortisBC will be reviewed and any cost adjustments identified.

The primary issue facing the Company with respect to BC MRS is the adoption of new standards, or the revision of existing standards which are outside the Company's control. As a result, changes and additions to BC MRS could have a material impact on the effort required to maintain full and auditable compliance. The impact of changes on the Company's operations is unavoidable once the standards are adopted by the Province. In addition, the BCUC will be auditing FortisBC at minimum once every three years for compliance with the adopted standards. Adjustments to processes and efforts may be required based on the results of the audits and may require adjustments to operating costs.

Table 4.3.4.3 Mandatory Reliability Standards O&M Cost Summary (2007-13)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	Full Time Equivalents					6	5	5
		($000s)						
2.0	Expenses							
2.1	Labour	-	-	-	-	752	905	914
2.2	Non Labour	-	-	-	-	203	274	273
TOTAL O&M EXPENDITURE:		-	-	-	-	955	1,179	1,187

Analysis of Forecast O&M Expenditure and Cost Drivers

The O&M expenses include the costs to maintain full and auditable compliance with the BC MRS. This includes efforts on monitoring and maintaining security systems, field maintenance, ongoing reporting requirements for the various standards, documentation and records, conducting self audits, participating in BCUC audits, ongoing training and participation in user groups, and evaluating impacts on changes to existing standards and adoption of new standards.

The effort and costs associated with BC MRS are transitioning from capital expenditures to maintaining compliance. In 2010, 100 percent of the effort in 2010 was capital. In 2011 the effort will transition to approximately 70 percent operating and 30 percent capital. In 2012 and 2013, 100 percent of the effort will be operating in nature. The shift from capital to operating results in a net increase of $0.224 million to the budget from 2011 to 2012.

The labour required to maintain auditable compliance and expenses to support these activities results in an increase in 2011 but is relatively consistent from 2012 to 2013.

Management of Cost and Efficiency

FortisBC continually focuses on cost control and cost saving initiatives. Field maintenance initiated by BC MRS is reviewed in conjunction with other maintenance and capital work to maximize crew effectiveness. In addition, tools and refinement of processes will continue to be reviewed and adjusted to minimize cost.

4.3.4.4 COMINCO FACILITY CHARGE

The Facilities Sharing Agreement between Teck and FortisBC provides for the shared use of Teck facilities. The cost for this use is billed on an annual basis in the amount of $0.046 million. This Agreement was originally approved by Commission Order E-7-96.

4.3.4.5 BRILLIANT TERMINAL STATION:

In 2003, the Company entered into a long-term lease of the Brilliant Terminal Station (BTS). Under both US and Canadian generally accepted accounting principles (US GAAP and C GAAP) and International Financial Reporting Standards (IFRS) the BTS lease is required to be recorded as a capital lease. However, for regulatory purposes it is treated as an operating lease in accordance with BCUC Order G-2-04:

> *"The Commission approves for [FortisBC] the variance from GAAP to treat the lease obligation for the Brilliant Terminal Station agreement as an operating lease, rather than a capital lease. Approval is granted to [FortisBC] for the establishment of a deferral account for the Brilliant Terminal Station Expense."*

A timing difference exists between the recovery of the capital cost of the BTS, the cost of financing the BTS obligation and the related operating costs, and the BTS lease payments made on a cash basis (as an operating lease). Therefore the Company is requesting regulatory approval to continue to recognize the timing differences related to the BTS lease in a non-rate base deferral account.

Analysis of Forecast O&M Expenditure and Cost Drivers

BTS costs are comprised of annual operating expenses and a capital charge representing a return on investment to Columbia Power Corporation/Columbia Basin Trust (CPC/CBT), in a manner similar to the Brilliant Power Purchase Agreement. FortisBC expenses a forecast amount in the test period and calculates a "true-up" for variances to forecast in its next Revenue Requirement Application, shielding customers from forecast risk.

With the completion of the Brilliant Expansion in 2007, 1/7 of the operating costs related to the BTS were charged to Brilliant Expansion Power Corporation. This change resulted in a reduction of the annual costs paid by FortisBC.

Table 4.3.4.5 Brilliant Terminal Station O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**							
		($000s)						
2.0	**Expenses**							
2.1	Labour	-	-	-	-	-	-	-
2.2	Non Labour	3,222	3,206	3,054	3,069	2,987	3,160	3,192
TOTAL O&M EXPENDITURE:		3,222	3,206	3,054	3,069	2,987	3,160	3,192

4.3.4.6 INTERNAL AUDIT

Business Responsibilities

The Internal Audit department is responsible for planning and conducting reviews and audits. This department also conducts the Company's annual risk assessment process, and monitors and evaluates the effectiveness and efficiency of the Company's internal controls. In recent years additional duties involving projects such as operational audits, Pandemic Response preparations, Enterprise Risk Management and Mandatory Reliability Standards have been taken on. Internal Audit's work is becoming increasingly more relied upon by the external auditors, saving them time and duplication in their own testing. This helped to keep the Company's external audit expense stable for 2011 with no increase over the prior year.

Business Issues / Challenges

Changes in financial reporting issues (IFRS, US GAAP, Governance, etc.) create a need for continuous professional development and research. In addition, finding suitable staff that has the appropriate training and experience required to be effective auditors has proven to be difficult.

Table 4.3.4.6 Internal Audit O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	1	2	2	2	3	3	3
					($000s)			
2.0	**Expenses**							
2.1	Labour	172	257	277	284	254	326	333
2.2	Non Labour	191	77	71	76	94	70	60
TOTAL O&M EXPENDITURE:		364	334	348	360	348	396	393

Analysis of Forecast O&M Expenditure and Cost Drivers

The majority of Internal Audit O&M expense consists of labour and benefits. Any increase in the number of staff also has an effect on other costs such as travel, training and office expense.

A second staff member for Internal Audit was hired during November 2007 which resulted in a decrease in the use of external contractors. Labour costs decreased in 2011 due to not using external contractors and a delayed hiring of a third staff member for the Kelowna office until mid-year.

Analysis of Historical Trends and Forecast Outlook:

O&M costs have increased by approximately eight per cent between 2007 and 2013 even with the addition of two staff. Prior to 2008, Internal Audit's main focus was ensuring that the Company would be ready to meet the certification requirements of NI 52-109 with respect to Internal Controls over Financial Reporting (ICFR) and Disclosure Controls. Since that time, requests from management and annual risk assessments have identified other areas that should be examined and these have been added to Internal Audit Plans in subsequent years. Some of these are only one time projects and others, due to their nature, are reviewed on a more regular basis.

Some examples of the new projects include various operational audits, Enterprise Risk Management, Mandatory Reliability Standards, preparations for the Pandemic Response, assistance with the HST Implementation, I.T. Disaster Recovery testing, coordinating the bi-annual I.T. Penetration Test, monitoring of the US GAAP / IFRS preparations, and proposed audit services for the Waneta expansion project. These additional projects have, over time, resulted in the need for increased resources to address the workload.

It became clear that with available resources there was a risk of not being able to complete all of the proposed work for 2011 while still being able to ensure that sufficient testing of Internal Controls continues to support the quarterly and annual certification process. The option of using a contractor was not considered to be practical, as there are very few, if any, qualified and experienced Internal Audit contractors available. From previous experience, contractors expect a premium hourly rate and when they leave all accumulated knowledge goes with them. It was decided as a result of the extra workload that the preferred approach was to hire the third staff member for the Kelowna office.

Contractor expense includes the cost of the annual Information Technology general controls (ITGC) testing, internal control reviews, penetration testing in IT and Enterprise Risk Management (ERM) documentation and testing. A significant portion of this work is now scheduled to be completed by Internal Audit staff rather than external consultants and this will reduce expense and create ongoing efficiencies.

Management of Cost and Efficiency:

The Company has hired permanent staff members to reduce reliance on contractors, which has also helped to reduce costs and retain knowledge within the Company.

4.3.4.7 LEGAL AND REGULATORY

Business Responsibilities

The Legal and Regulatory department's primary responsibilities include managing legal and regulatory compliance, prudently mitigating legal exposure and maintaining relationships with the BCUC, interveners, customers and other stakeholders.

Business Issues / Challenges

Continued pressure on customer rates and increased complexity of regulatory processes poses challenges in terms of maintaining positive regulatory relationships. The Company's rate increases, which have been magnified by slow customer load growth, have been primarily driven by capital expenditures, which were necessary to upgrade and maintain the Company's aging infrastructure, and from increasing power purchase costs. As regulation and its relationship with government policy continues to become more complex, there may be increasing cost pressures on the Company's regulatory activities.

In addition, the Company's business has become more complex due to the changes in legislation and provincial policy. This increasing complexity is accompanied by increased legal activities to ensure ongoing compliance and risk mitigation.

The complexity of regulatory processes has also been increasing in recent years. Regulatory processes are typically attracting more interveners, taking longer, and costing more than in previous years. This increased interest, and the associated time and cost requirements continue to put pressure on the Company's regulatory and other resources. Although the Company is struggling to maintain the current level of regulatory process and activity, it is not planning to increase personnel for regulatory processes at this time.

Table 4.3.4.7 Legal and Regulatory O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	7	8	7	7	8	8	8
					($000s)			
2.0	**Expenses**							
2.1	Labour	768	1,015	887	803	1,122	1,130	1,158
2.2	Non Labour	413	278	405	648	380	390	390
TOTAL O&M EXPENDITURE		1,181	1,293	1,292	1,451	1,502	1,520	1,548

Analysis of Forecast O&M Expenditure and Cost Drivers

The 2012 and 2013 O&M budget for the legal and regulatory departments are increasing by approximately 1 percent and 2 percent respectively over the previous year. The increases are primarily comprised of labour escalations.

Analysis of Historical Trends and Forecast Outlook

The Legal and Regulatory department has experienced generally inflationary increases in its O&M for all years other than from 2008 through 2010. During 2008 a director position was added to the Regulatory department due to increasing regulatory priorities which resulted in a step change in legal and regulatory costs. During 2009 and 2010, there were vacancies in the department causing a decrease in labour costs. During 2010, the Company incurred increased consultant and legal costs primarily related to backfilling the vacancy and increased regulatory activity during the year and in preparation for the 2012-13 Revenue Requirements and 2012 Integrated System Plan Application.

Management of Cost and Efficiency

The legal and regulatory department attempts to operate at a consistent level of internal resources while utilizing consultants to assist with shorter-term peak requirements. It also ensures that any utilization of external legal or regulatory resources is only done when prudent and necessary. The Company attempts to schedule legal and regulatory processes evenly throughout the year to avoid resourcing conflicts and the resulting increase in costs.

4.3.4.8 CUSTOMER SERVICE

Business Responsibilities

The FortisBC Customer Service department is responsible for six main functional areas:

1. **Billing and Customer Systems**

   The Billing department is responsible for the accurate and timely issuance of customer billing statements, as well as the accounts receivable associated with electricity sales. In performing this function, the Billing department ensures that billing premise locations are maintained, potential billing errors are identified and corrected, and customer billing statements are printed or emailed.

2. **Meter Reading**

   The Meter Reading department is responsible for the manual reading of customer meters. Some readings are obtained by wireless drive-by devices or remote interrogation, but the majority require a meter reader to drive to a reading route, physically attend customer premises, visually read the meter and enter the reading into a handheld device.

3. **Customer Contact Centre**

   The Customer Contact Centre is the primary first contact for the majority of customers. The highest volume of contacts relate to new customers, customers who are moving premises, power outages and billing statement enquiries. The contact centre is also responsible for collection activities related to overdue accounts.

4. **Key Account Management**

FortisBC's largest customers are assigned a Key Account Manager, who is the first point of contact for billing and collection enquiries and any other issues large customers may want to address.

5. Demand Side Management

The FortisBC Demand Side Management program is known as PowerSense to its customers. The PowerSense program provides information and financial incentives related to the choice of equipment and customer behaviours that will result in reduced electricity consumption. This activity has been included in the department narrative for completeness as it is a function of the Customer Service department, but is not included in O&M Expense.

6. Advanced Metering Infrastructure

The Customer Service department includes the project team that is preparing a CPCN application for an Advanced Metering Infrastructure (AMI) project that, if approved, would result in the deployment of "smart meters" throughout the FortisBC service territory. This activity has been included in the department narrative for completeness as it is a function of the Customer Service department, but is not included in O&M Expense.

Business Issues / Challenges

Customer growth results in upward pressure on customer service costs. Therefore, FortisBC seeks out ways to mitigate these potential cost increases by improving efficiencies in numerous ways throughout its Customer Service operations. Some examples are discussed below.

Table 4.3.4.8 Customer Service O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	61	61	64	68	71	71	69
					($000s)			
2.0	**Expenses**							
2.1	Labour	4,184	4,046	4,152	4,329	4,611	4,783	4,830
2.2	Non Labour	1,970	2,226	1,683	1,646	1,801	1,954	1,976
TOTAL O&M EXPENDITURE:		6,154	6,272	5,835	5,975	6,412	6,737	6,806

The increase of seven FTEs between 2009 and 2011 is due to:

- two additional employees for the Advanced Metering Infrastructure project team (fully capitalized);
- one additional Customer Service Representative in the Trail Contact Centre to handle LiveSmartBC enquiries (as part of a contract with the BC provincial government); and
- four additional employees in the PowerSense department to coordinate, manage and monitor the increased DSM program expenditures.

Analysis of Forecast O&M Expenditure and Cost Drivers

There are no significant changes in cost drivers or increases in expenditures for 2012 and 2013; increases are being held to approximately inflation plus customer growth.

Management of Cost and Efficiency

FortisBC seeks out ways to mitigate potential cost increases by improving efficiencies in numerous ways throughout its Customer Service operations. Specific actions that have created efficiencies include:

- reduced postage and printing costs due to eBilling;
- improved collections processes and reduced write-off period;
- automation of various billing and collections processes;
- automated planned outage and collections calls;
- taking on third-party work (such as LiveSmartBC) in the contact centre and improving utilization of existing Customer Service Representatives;
- increasing third-party revenues from pole contacts; and
- improved user interface for Customer Information System.

The cost savings from most of the above items (aside from eBilling) is manifested in improved efficiency which creates more time for existing staff to absorb customer growth. This effect is demonstrated by the fact that the customer service budget is forecast to rise at an annual growth rate of 1.7 percent over the period 2007-2013, while unit labour costs have seen an annual growth rate of approximately 3.3 percent over the same period. Labour costs account for approximately 70 percent of total Customer Service expenditures. As a result of the above efficiencies, no significant organizational changes are anticipated during 2012 and 2013.

4.3.4.9 COMMUNITY & ABORIGINAL AFFAIRS

Business Responsibilities:

The FortisBC Community and Aboriginal Affairs department has three primary areas of responsibility and accountability.

1. **Aboriginal Relations**

   FortisBC's aboriginal relations program focuses on initiating, developing, and maintaining sustainable business relationships with the First Nations with whom the Company normally does business. A significant portion of FortisBC's facilities are located on First Nations land, both reserve and traditional, and it is imperative that the relationships are rigorous enough to withstand numerous external and internal pressures.

2. **Community Relations**

   FortisBC will continue to build on its consultation and communications activities with various levels of municipal and regional governments. Local governments are key influences and their decisions impact the Company, therefore there is an increased need for a consistent approach to municipal relations. Among other objectives this approach will ensure concerns or issues are responded to in a timely manner, reducing potential risk to project timelines or regulatory involvement.

3. **Community Investment**

   Through the strategic development and deployment of the corporate Community Investment program, FortisBC provides donations and sponsorship support to the communities, including First Nations within its service area. This program helps FortisBC and its employees connect with customers and employees through a variety of local initiatives and contribute to the economic and social fabric of the communities the Company serves, while maintaining its corporate reputation.

Business Issues / Challenges

Local Municipal Governments

FortisBC is dedicated to working with local governments to foster and build relationships with government officials, mayors and council in the communities it serves. FortisBC is in the forefront with municipalities to inform them of corporate initiatives, project developments and potential rate changes that may impact their communities and residents.

FortisBC includes municipalities in the decision making process for large projects and infrastructure upgrades. The Company is open to feedback, invites dialogue and discussion regarding its corporate activities. In the event of major service interruptions FortisBC is prepared to safely deliver and restore services.

First Nations

FortisBC's success in developing and maintaining its First Nation relationships supports the Company's ability to move projects and programs forward in a timely manner. The Company's objective is to exceed customer expectations and to safely provide efficient, reliable energy services at the lowest reasonable cost.

FortisBC has worked to establish open and consultative relationships with First Nations and Aboriginal communities. This is fundamental to making decisions that appropriately reflect and incorporate First Nation interests and interests of the Company and its customers.

FortisBC is committed to preserving and building upon the relationships it has created with First Nations and Aboriginal communities. The Company's focus is to place a strong emphasis on building long-term constructive and respectful relationships with First Nations and Aboriginal communities recognizing the uniqueness and diversity of their cultural heritage.

The Company intends to continue to notify and consult with the Bands and First Nations and Aboriginal communities impacted and affected by its operations. FortisBC seeks to be in communication and accept constructive input and feedback on possible challenges.

A combination of the increasing complexity of First Nations issues and the size of the geographic area of the FortisBC service territory is putting upward pressure on the existing resources assigned to maintaining these relationships.

Table 4.3.4.9 Community and Aboriginal Affairs O&M Cost Summary 2007-2013

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	1	1	1	1	3	3	3
					($000s)			
2.0	**Expenses**							
2.1	Labour	121	143	146	188	245	266	259
2.2	Non Labour	21	43	7	383	349	408	430
TOTAL O&M EXPENDITURE:		143	186	153	571	594	674	689

Analysis of Forecast O&M Expenditure and Cost Drivers

The community and aboriginal affairs department is budgeting increased costs for local government relations and consultation requirements for First Nations due to the increasing complexity of these relationships. In addition, the Community Investment Program was transitioned from the communications department to this department during 2010.

4.3.4.10 COMMUNICATIONS

Business Responsibilities

The Communications department is responsible for coordinating the Company's corporate and customer communications which involve employee communications, customer communications, advertising, public education, social marketing, media relations, website content, social media, and community outreach initiatives. The department is responsible for power outage communications, management of media relations, internal and external communications about Company initiatives, projects and other developments, and responding to public, stakeholder and media enquiries. The department also coordinates customer, stakeholder and employee communications materials including newsletters, brochures, bill inserts, website/intranet content, annual report, advertising and other public materials to support key business communications needs. These include public and employee safety, energy efficiency and other messaging.

Business Issues / Challenges

Given the nature of FortisBC's business, it is important that the Company communicates openly about its activities, engages stakeholders in meaningful dialogue about developments that affect them, and contributes positively to the economic and social fabric of the communities FortisBC serves.

There remains significant public interest in corporate initiatives, operational activities and infrastructure improvement projects. There is also a need for targeted and strategic effort around safety and energy efficiency communications. The communications group leads communications on these activities to facilitate opportunities for open dialogue, information sharing and long-term cooperative relationships.

Management of communication through the Company's communications group ensures all communications efforts are effective and efficiency is maximized through coordination, resource sharing and consistency.

Ongoing efforts include communications related to new projects, power outage and emergency situations, operations and maintenance activities, rates and regulatory initiatives, safety, energy efficiency, and environment.

Table 4.3.4.10 Communications O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	3	4	4	5	5	5	5
		($000s)						
2.0	**Expenses**							
2.1	Labour	285	288	352	367	487	532	543
2.2	Non Labour	575	605	645	700	416	391	409
TOTAL O&M EXPENDITURE:		860	893	997	1067	903	923	952

Analysis of Forecast O&M Expenditure and Cost Drivers

The 2012 and 2013 O&M Expense forecast for the communications department is increasing by 2.2 percent and 3.1 percent in each respective year. There is some increased requirement for travel between areas of operation. Other increases are being held at inflationary growth levels.

Analysis of Historical Trends and Forecast Outlook

The Communications team has grown since 2007 by two FTEs; 1.5 FTEs to support the PowerSense DSM program communications needs, and the remainder to support overall customer, stakeholder and employee communications. During 2011, the community investment program was transitioned from the communications department to the community and aboriginal affairs department, and the budget associated with employee events was transitioned to the human resources department.

4.3.4.11 HUMAN RESOURCES

Business Responsibilities

The overall goal of the HR function is to ensure that the Company's workforce, now and into the future, has the level of skill and capacity to achieve the Company's business goals and objectives. The HR department performs and provides different services to support management of the Company's workforce to ensure effective and efficient alignment with its business plans. The following sections provide an overview of the activities and responsibilities within each of the functional areas in the HR department.

Employee Relations

Provides direction and delivery of labour relations and advisory services in an effort to maintain and foster a productive and cooperative employee relations climate. Areas of responsibility include:

- Employee and labour relations;
- HR Advisory services;
- Recruiting;
- Coordination of management training and leadership development;
- Attendance management;
- Collective agreement administration;
- Collective bargaining and contract negotiations;
- Compliance training;
- Learning content management;
- Competency management and administration; and
- Training records.

Compensation, Benefits and Pensions

- Administration of the Company's various benefits plans, pensions, compensation, and incentive pay programs; and
- Disability management.

Payroll and HRIS

- Payroll and Time Administration;
- Human Resource Information Systems (HRIS) and Master Data;
- HR metrics / surveys and reporting;

Business Issues / Challenges

Like many other organizations faced with an aging workforce and a shrinking global talent pool, FortisBC faces the challenge of approximately half of its current combined workforce becoming eligible to retire in the next five years. HR must continue to work closely with the Company's management team to facilitate effective knowledge transfer and transition planning. The positions that require particular focus are Power Line Technicians, Meter Technicians (to meet requirements for AMI), Communication, Protection and Control Technologists and Power System Dispatchers.

FortisBC's Non-Union, IBEW and COPE defined benefit pension plan valuations will be completed by June 2011. Approximately 75 percent of employees are enrolled in current pension plans that are funded by contributions from both the Company and the employee.

The FortisBC and COPE Local 378 Collective Agreement expired on January 31, 2011 and the parties are in the process of commencing negotiations. The collective agreement with IBEW Local 213 expires January 31, 2013 and collective bargaining is expected to commence in 2012.

Table 4.3.4.11 Human Resources O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	9	14	13	14	14.2	14.5	14.5
		($000s)						
2.0	**Expenses**							
2.1	Labour	1,028	1,197	1,261	1,309	1,297	1,411	1,370
2.2	Non Labour	673	342	297	329	492	429	504
TOTAL O&M EXPENDITURE:		1,701	1,539	1,558	1,638	1,789	1,840	1,874

Analysis of Forecast O&M Expenditure and Cost Drivers

Codes and Regulations

Upgrades to the ADP Payroll system to ensure compliance with collective agreements and pension plans will be completed during 2011 resulting in an increase to O&M Expense in 2012. The increase is due to the removal of an equivalent credit to HR for labour charged out to this capital project in 2011.

Actual costs for contracted labour were higher than normal in 2010 due to increased costs related to arbitrations. Historically, these costs have been in the $0.08 million to $0.1 million range.

Centralized training expenses for compliance and mandatory training have remained relatively stable over the past several years, in spite of a significant increase in the number of training programs being offered.

Budget Transfers

Other miscellaneous cost increases between 2011-2013 are due mainly to a transfer of costs to HR from the Communications budget for employee events, resulting in a corresponding reduction in that budget.

Analysis of Historical Trends and Forecast Outlook

Between 2007 and 2008 there was significant restructuring of the HR department in response to evolving business needs as well as the need to improve service levels in some key areas. Some of these changes were made possible by attrition (retirements, resignations, terminations) while additional resources were brought in to improve HR service delivery in advisory services, benefits, pension and payroll administration, as well as compliance training. The equivalent of 1.5 FTEs were transferred in from Health, Safety and Environment to focus on compliance training. The net result was an increase of five FTEs, from nine in 2007 to 14 in 2008.

4.3.4.12 INFORMATION SYSTEMS

Business Responsibilities

The Information Systems (IS) department is responsible for the reliable operation of all software applications, data and the supporting infrastructure, including telephony, required to deliver these technology requirements to 14 FortisBC offices, four generating plants and mobile users. A number of the technologies that the department is responsible for are integral to safety, as they are relied upon to deliver critical information and communications to operations. The total value of all assets that the IS department is responsible for is approximately $62 million, which also includes operational technology such as System Control and Data Acquisition (SCADA), data historian and maintenance management systems. Maintaining reliability involves comprehensive asset management to ensure infrastructure is reliable and supported by vendors, as well as ensuring all applications and databases remain up to date. The department is also responsible for all operating costs associated with these software and hardware assets as well as the costs for the Wide Area Network (WAN) managed by Telus Communications Inc. (Telus). This includes the management of costs and services based on the needs of individual locations ensuring appropriate performance is balanced with cost.

The IS department is responsible for ensuring cyber security and change control requirements are met and are subject to annual audits to confirm this. This includes compliance with the Cyber Infrastructure Protection (CIP) requirements as specified by MRS. Disaster recovery planning and capabilities for both operation and corporate infrastructure and systems are included in this area of responsibility.

The IS department is responsible for providing end user technical support for all employees and contractors for all applications and associated equipment.

IS is also responsible for the management and monitoring of all telephony contracts, including cellular. Individual usages are monitored by the IS department to ensure the correct contract options are applied on an individual basis to maximize value from contract options.

The Company analyzes life cycle management of all technology assets to ensure maximum life expectancy is realized from each asset without jeopardizing reliability and productivity. Life cycle management also includes the proper disposal of expired assets. Old equipment must be collected and delivered to the appropriate recycle locations.

Business Issues / Challenges

As technology is used more extensively throughout every area of the business it is important that the Company evaluates the benefits of existing systems and additional functionality available through standard upgrades. This evaluation may involve training and seminars with peers to learn best practices regarding the technology use. It can also require process reviews as technology and business requirements change to ensure the benefits of the most current version of the technology is being realized.

System Integration Issues

A number of very robust systems have been implemented over the past five years. The challenge is connecting the core systems and information in a way that is seamless and single point for the end user. The long term strategic plan for IS department is "single sign-on" for all users. "Single sign-on" would be a thin client web style page that would have all the necessary information for individual users presented. The users would simply access the information they needed regardless of what system and database it was in. All requests from the user interface would pass through an Enterprise Service Bus (ESB) that would automatically push and pull information and data to all the appropriate systems. This is a long term strategy that all architecting for new projects and enhancements is based on. There are areas of the business such as customer service and designing that would realize the most benefits from this direction. By connecting these systems, business efficiency could be enhanced.

Table 4.3.4.12 Information Technology O&M Cost Summary (2007-2013)

	General Assumptions	**2007A**	**2008A**	**2009A**	**2010A**	**2011F**	**2012F**	**2013F**
1.0	**Full Time Equivalents**	22	26	29	26	27	28	28
					($000s)			
2.0	**Expenses**							
2.1	Labour	1,537	1,659	1,736	1,698	1,713	1,665	1,620
2.2	Non Labour	1,328	1,174	1,202	1,126	1,102	1,176	1,226
TOTAL O&M EXPENDITURE:		2,865	2,834	2,938	2,824	2,815	2,841	2,846

Analysis of Forecast O&M Expenditure and Cost Drivers

The O&M Expense forecast for the IS department includes all labour, licensing, maintenance, training, travel and other expenses associated with operating and maintaining all applications, infrastructure, WAN and telephony as described previously. It also includes all printing costs, excluding paper, for the Company.

Analysis of Historical Trends and Forecast Outlook

Support costs, particularly for software, have increased 3 to 4 percent on average over the past three years. Wages have also increased an average of approximately 3 percent annually over the past five years. Increased reliance on technology for all areas of the business has increased complexity and demand on support for both application and infrastructure. The desire to deliver more and better information to users where and when they need it has motivated the use of new technologies. The IS department must be trained on all technologies used by the organization in order to provide the necessary support. This requires ongoing training, which is generally offered only in specific locations by each technology provider putting pressure on training costs and associated travel and accommodation costs.

Management of Cost and Efficiency

IS continually focuses on cost control and saving initiatives. Savings have been realized through the prudent management and review of telephony, printing, managed network, licensing and other contracts managed by the IS department. Beginning in 2010, $0.023 million was saved annually on the total cellular costs for the organization by managing user plans based on flexibility in the contract.

By centralizing printing on larger multifunction devices for groups of users, printing costs have been reduced by over 50 percent when compared to printing to smaller individual devices. Printing costs on the large multifunction devices also include support and parts from the vendor, as compared to having to support smaller individual devices in-house.

New technologies are also leveraged to save support and other costs associated with operating infrastructure, applications and databases. Remote control and management tools allow support staff to assist users from a central location reducing travel time. Server management tools enable support staff to monitor and control infrastructure, applications and databases from almost any location where they have cellular connectivity, improving reliability while allowing the same number of staff to support more systems.

Server virtualization technology has become a standard at FortisBC, which allows several "virtual" servers to reside on a single physical server. This has reduced physical server requirements by approximately 10 to 1, as compared to traditional server configurations. This has reduced and mitigated annual energy consumption by approximately 150 kW, or approximately $0.1 million annually, consequently reducing cooling requirements.

Desktop virtualization has shifted the processing requirements of the user's environment from their local machines to a server based platform. This reduces processing requirements at the desktop level, thus extending the life of older units and reducing the costs of replacement laptops and desktops due to decreased performance requirements. Desktop virtualization also reduces the support costs per user due to the ease of supporting a virtual desktop from a central location.

4.3.4.13 HEALTH SAFETY AND ENVIRONMENT

Business Responsibilities

FortisBC has established an Environment and Safety management system which systematically addresses the risks associated with the construction, operation and maintenance of the facilities and sets forth policies, standards and procedures that are in compliance with legislation and regulations to protect the safety of its employees and customers and the species and the environment in general. The Health, Safety and Environment (HS&E) department is responsible for the measuring, monitoring, and reporting of the integrated corporate HS&E and security management systems. The compliance with applicable health, safety and environmental regulations and internal guidelines, injury prevention and loss prevention mandates are carried out through the implementation of the safety, security and environment management systems. These systems document expectations from senior management and regulators including setting targets for continuous improvement. Environment, health and safety are integrated into each manager's areas of responsibilities.

Business Issues / Challenges

The Company builds, operates and maintains about 7,000 km of power lines and 70 major facilities in proximity to a sensitive environment with high safety hazards. FortisBC is committed to compliance with applicable HS&E requirements in operating these existing facilities and also in constructing new projects. This presents a challenge to the Company as health, safety, and environment requirements are constantly changing due to newer legislation and more recent industry best practices.

There have been many changes or enhancements in the last five years with respect to safety and environment legislation, public expectation and awareness. Enhanced requirements occurred in areas such as:

- General hazard requirements with respect to confined space, cranes and hoists, avalanche and working alone;
- Notice of projects;
- Facilities applications for activities;
- Environmental impact assessments (federal and provincial);
- Environmental assessment screenings (federal and provincial);
- Fisheries Act Authorizations (e.g., approved work practices for riparian vegetation management limits; Vegetation management activities around fish-bearing streams to protect and conserve riparian habitat);
- Greenhouse gas monitoring and reporting
- SARA incidental effects permits;
- Navigable Waters Protection Act;
- Riparian Areas Regulation and other provincial regulations;
- Provincial approvals for specified work activities or when specified areas are impacted including work impacting watercourses or wetlands, herbicide use, and municipal work permits; and
- Security monitoring and control.

The following discussion identifies certain areas that FortisBC is currently monitoring.

PCB Regulations

FortisBC established a Polychlorinated Biphenyls (PCB) testing and monitoring program in response to Environment Canada's review of PCB regulations. FortisBC initiated additional effort to deal with PCB health and environmental concerns and the release of draft PCB regulation in 2002. The draft regulation suggested that depending on level of concentration some items would be required to be removed from service. To ensure worker health and safety and compliance with the pending regulation, FortisBC submitted the PCB test program to the

BCUC as part of its 2005 Revenue Requirements Capital and details on the Company's proposed seven year PCB oil sampling program.

In September 2008, the new PCB Regulations under the Canadian Environmental Protection Act were enacted. The Regulations set specific deadlines for elimination of equipment with PCB concentrations at or above 500 ppm. Pole top transformers were exempted until 2025. It also establishes best management practices for the remaining PCBs in use (i.e. those with content of less than 500ppm). Environment Canada continues to apply pressure to remove PCB contamination from oil filled equipment through regulation and enforcement. The Regulations now prohibit the release of one gram or more of PCB from operating equipment and zero tolerance for PCB release from scrap equipment.

FortisBC was granted an extension to 2014 to remove equipment and oil containing PCB concentration than 500 ppm. All other equipment with concentrations between 500 ppm and 50 ppm must be removed by 2025. This includes instrument transformers, bushings, capacitors, switches, etc.

The requirement for zero PCB release from stored equipment and less than one gram of PCB threshold for operating equipment has increased pressure to replace or retrofit complete containment on any oil filled equipment and processes involving PCB contaminated equipment where PCB contamination is measureable. Increasing resources are continually required to measure, monitor, and reporting PCB removal or releases.

Invasive Species

Invasive aquatic mollusc species including zebra mussels, quagga mussels and New Zealand mud snails are spreading west. Although these species have not been found in the Kootenay and Columbia River systems to date, FortisBC must be ready to deal with prevention and control of these invasive species. Eurasian Milfoil is an invasive aquatic plant that has now entered the Kootenay Lake. The weed spreads very quickly through seasonal fragmentation. As lake temperatures increase the infestation will amplify, clogging intake trash racks and increasing the frequency and/or cost of maintenance of the racks.

FortisBC will continue to fund educational efforts directed at boaters and plan for increased trash rack maintenance or consider long term capital projects for installation of rakes where not already present at generating facilities. Invasive terrestrial plant species are increasing in complexity and obtaining approvals for the use of pesticide control measures is becoming more difficult. The result is an increased demand on environmental resources to assure regulatory compliance and public acceptance.

Species at Risk

SARA has generated some uncertainty and concern for the hydropower industry. Presently FortisBC and all other facility operators manage the Columbia River white sturgeon population that is listed as endangered. Although they are not actively being managed, there are three additional fish species in the river system that are listed under SARA including Shorthead Scuplin (threatened), Columbia Sculpin (special concern) and Umatilla Dace (special concern).

The uncertainty around SARA is specific to how the Department of Fisheries and Oceans Canada (DFO) is managing and interpreting the SARA conditions and the ongoing court challenges by environmental groups that DFO faces when they attempt to implement the regulations. Resolution of the issues is slow and therefore planning is challenging. Monitoring hydroelectric facilities on the system for compliance with SARA has increased resource requirements.

Other Hazardous Materials

Incandescent light bulbs are now banned in British Columbia, which necessitates the use of compact fluorescent or other bulbs. Most lighting ballasts contain mercury so there may be a small incremental increase in cost to manage additional mercury containing wastes.

Greenhouse Gas

FortisBC is mandated to monitor and report Greenhouse gas emissions. Although it is still being assessed, there may be a positive impact to generation if run of river projects are considered as offsets in carbon trading. However it is likely that this would only apply to new facilities.

In sum, monitoring, reporting, or complying with safety, security and environmental requirements are increasing the time, efforts and costs required to obtain permits, licenses, and authorizations to build, operate and maintain facilities.

System Integration Issues

A number of safety and environment management systems have been implemented over the past five years. The challenge is connecting the independent systems and information in a way that the end user can access and utilize the data to influence good business decisions. The long term strategic plan for HS&E systems is to be consistent with the ISO 14001 model with software that will fully integrate with existing business management systems.

Table 4.3.4.13 Health, Safety and Environment O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	6	6	6	7	8	8	8
					($000s)			
2.0	**Expenses**							
2.1	Labour	426	458	480	586	696	725	760
2.2	Non Labour	219	157	164	141	211	200	193
TOTAL O&M EXPENDITURE:		645	616	645	727	907	925	953

Analysis of Forecast O&M Expenditure and Cost Drivers

The O&M forecast for HS&E includes all labour, maintenance, training, travel and other expenses associated with operating and maintaining all safety, security and environmental management systems. An Administration Assistant was hired in 2010 to manage the administrative load of the new management system and reporting requirements. A Security Coordinator was added in 2011 to assist with increasing legislated security requirements and copper theft.

Analysis of Historical Trends and Forecast Outlook

Wages have increased an average of three percent annually over the past five years. Increased compliance requirements for all areas of the business have become more complex, which has increased demand on support for compliance measuring and monitoring. .

Management of Cost and Efficiency

Efforts are focused on reducing injury, illness and incidents that may cause an unnecessary cost to the Company and its customers. Efficacy is established by having an integrated health, safety, environment and security team placed at the main business locations to directly measure, monitor and minimize Company losses.

4.3.4.14 FACILITIES MANAGEMENT

Business Responsibilities

The Facilities department is responsible for operating and maintaining all FortisBC facilities. The services range from building asset operation and maintenance, physical security, space planning, office furniture and equipment and mailroom services. The department ensures

FortisBC employees have a suitable work environment with safe and efficient buildings and workspaces.

Table 4.3.4.14 Facilities Management O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	3.5	4.5	7	7	5	5	5
		($000s)						
2.0	**Expenses**							
2.1	Labour	295	379	510	578	423	491	499
2.2	Non Labour	2,424	2,455	3,027	3,122	3,197	3,195	3,217
TOTAL O&M EXPENDITURE:		2,718	2,834	3,537	3,700	3,620	3,685	3,716

Analysis of Forecast O&M Expenditure and Cost Drivers

Changes in expenditures in Facilities in 2012 will allow Facilities to deliver a suitable work environment with safe and efficient buildings and workspaces.

The 2012 increases are driven by the following:

- Cyclical Building Maintenance and Service Contact increases;
- Labour inflation increases;
- Office expenses increase for items like postage, couriers and off-site record storage and other miscellaneous costs.

For 2013, the forecast includes a decrease as a result of a reduction in the Kelowna Enterprise lease, partially offset by cyclical maintenance and service contract increases.

Analysis of Historical Trends and Forecast Outlook

The Facilities department continues to provide efficient and effective asset management practices and support services to the Company. The Facilities department is responsible for a wide range of services with funding requirements fluctuating as a result of the market or service, including:

- Cyclical maintenance - This is preventative maintenance service to keep facility assets in good condition, improving equipment utilization and reliability, and ensuring the health, safety and welfare of employees. As this maintenance is cyclical, the spending pattern associated with these tasks varies based on manufacturer recommendations, best practices and code compliance. Maintenance levels will fluctuate over multiple years, with a corresponding impact on the forecast expenditures.

- Lease Contracts – FortisBC holds leases for three locations. Lease contracts have stepped rate increases, renewals and expiries that affect the required operating costs for the various facilities. Lease contracts demand market rates for the specific lease area.
- Service Contracts – Contracts for various services are competitively tendered and negotiated over a fixed term length. Contract increases can be stepped within the contract term or require renegotiation.

Management of Cost and Efficiency

The forecast changes in costs continue to be driven by contractual inflation and required service levels for operating and maintaining building assets. The changes are required to ensure Facilities can continue to deliver a suitable work environment with safe and efficient building and workspaces.

4.3.4.15 FINANCE AND ACCOUNTING

Business Responsibilities

The Finance and Accounting department is organized into three areas of responsibility:

Budgeting and Forecasting

The Budgeting and Forecasting group manages the Company's overall financial plans, annual operating budgets and forecasts including variance analysis and reporting, regulatory reporting including revenue requirements, capital plans and forecasts including capital expenditure accounting. The group also manages property taxes and provides support to the Company for various financial analyses.

Financial Reporting and Treasury

The Financial Reporting and Treasury group is responsible for short and long term financings, cash management and forecasting, communication with the credit rating agencies and debenture holders, preparation of monthly, quarterly and annual consolidated financial statements, quarterly and annual Management Discussion and Analysis, other continuous disclosure documents, preparing and implementing GAAP changes, financial reporting for taxes (year-end and quarterly tax provisions for current and future income taxes), and filing of tax returns and Harmonized Sales Tax (HST). The group is also responsible for maintaining the internal controls related to financial reporting and treasury, as well as accounting for employee future benefits and insurance.

Accounting and Financial Systems

The Accounting and Financial Systems group manages the general ledger, general accounting, cash and banking, miscellaneous accounts receivable, accounts payable, internal controls, and manages financial system upgrades, customizations, enhancements and modifications.

Business Issues / Challenges

The Finance and Accounting department has and continues to face the following business challenges:

Changes in Financial Reporting

Changes in accounting and financial reporting requirements have evolved considerably over the last several years. The Canadian Accounting Standards Board has been active in amending existing standards and adopting new standards, often times to deal with increasingly complex accounting issues. Certain of these accounting policy changes have resulted in adjustments to financial statement presentation and note disclosure, as well as changes to the financial reporting and accounting processes. Certain accounting policy changes may not have resulted in a financial statement or regulatory impact, however they have still required FortisBC to perform extensive research into Company facts and circumstances and the preparation of position papers to be provided to the Company's external auditors. Many of the changes made to Canadian GAAP have affected accounting practices normally applied by rate-regulated entities. Since 2005, FortisBC has been required to adopt and continue to assess several complex accounting standards in order to comply with Canadian GAAP. Most of the following accounting guidance has also been implemented as part of US GAAP and IFRS, notably:

- Disclosures by Entities Subject to Rate-Regulation (AcG-19), which significantly increased the required disclosures of rate-regulated entities to ensure transparency between regulatory accounting and accounting practices required under Canadian GAAP;
- Income Taxes (CICA 3465), which was amended to require rate-regulated entities to recognize previously unrecorded future income taxes arising from temporary differences between the tax and accounting basis of assets and liabilities;

- Capital Disclosures (CICA 1535), which required additional information to be disclosed regarding an entity's capital and the manner in which it is managed, including management objectives, policies and quantitative assessments;
- Financial Instruments (CICA 3855, 3861, 3862, and 3863), which required all financial assets and liabilities to be classified into categories based on their attributes, required an entity to search for and document any derivatives and embedded derivatives in contracts, and significantly increased the disclosures required on both qualitative and quantitative information on the nature and extent of risks from financial instruments to which an entity is exposed;
- Asset Retirement Obligations (CICA 3110 and EIC-159), which was effective for the reporting periods ended December 31, 2004 and June 30, 2006, respectively, required the determination of whether a legal liability existed to incur retirement costs at the end of an asset's useful life. This guidance required that the total retirement costs to be recorded as a liability at fair value, with a corresponding increase to property, plant and equipment. The application of this guidance required an extensive accounting and legal review of the Company's contracts upon adoption, as well as ongoing review and analysis.

Increased Internal Control Requirements

National Instrument 52-109 (NI 52-109) requires designated officers to certify that filings do not contain any misrepresentations, financial information is fairly presented, disclosure controls and procedures (DC&P) have been designed and are operating effectively, and internal controls over financial reporting (ICFR) are designed and operating effectively. NI 52-109 is generally referred to as the Canadian equivalent to sections 404(a) and (b) of the Sarbanes-Oxley Act (SOX) in the United States requiring internal control attestation. NI 52-109 was amended several times, which included some reductions in the level of attestation by venture issuers such as FortisBC, before becoming effective for the December 31, 2008 year-end. However, even with the decreased level of certification required by FortisBC, designated officers are still responsible for ensuring that processes are in place to support the representations being made. NI 52-109 resulted in significant amounts of work led by the Company's Internal Audit department, use of consultants, and extensive internal control procedures being implemented in all areas of finance, accounting, project management, and financial reporting.

Increased Treasury Activity

Since 2004, FortisBC has raised $550 million in public debt which now constitutes approximately 90 percent of the Company's total embedded long-term debt structure. The first public debt offering occurred in November of 2004 and the Company has issued debt in each of 2005, 2007, 2009 and 2010. Each of the offerings has required a prospectus to be filed and co-ordination of the Company's treasury group, executives, external auditors, lawyers and investment bankers. The increased debt levels are the result of the increased capital investment made by FortisBC in recent years. Additionally, annual renewals and amendments to the Company's operating bank credit facilities have been required to ensure sufficient flexibility has been available to manage the operations.

Changes in Audit Requirements

National Instrument 52-108 (NI 52-108) requires auditors of reporting issuers in Canada to be participants in the Canadian Public Accountability Board's (CPAB) oversight program. CPAB is a national agency responsible for the oversight of public accounting firms that audit Canadian reporting issuers. This oversight program is intended to benefit investors and Canadians in general by promoting high quality, independent auditing in order to contribute to public confidence in the integrity of financial reporting of reporting issuers in Canada. The role of CPAB in public practice has resulted in changes to the way audit firms assess risk, search for fraud, carry out the audit plan, assess misstatements, and report to audit committees. The effect of these changes in audit approach has led to increased focus on process level controls, increased level of supporting documentation to be provided to auditors, larger audit teams, longer audits, more testing, and increased audit fees.

Capital Expenditure Program

FortisBC has made significant investments in infrastructure since 2005. The administrative requirement for budgeting, managing, accounting for and reporting of capital expenditures has increased significantly while the Finance departmental structure has remained largely unchanged. As the Company has grown, synergies have been created between the Finance and Accounting groups to effectively manage the increased administrative requirements. The resulting effect has created a much more dynamic Finance group that is aware of the strategy, requirements and deliverables of other departments allowing a more focused effort to achieve common goals.

Table 4.3.4.15 Finance and Accounting O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	**Full Time Equivalents**	20	19	18	18	19	19	19
		($000s)						
2.0	**Expenses**							
2.1	Labour	2,066	1,899	1,866	1,959	2,305	2,343	2,398
2.2	Non Labour	803	583	603	658	787	932	962
TOTAL O&M EXPENDITURE:		2,869	2,482	2,469	2,617	3,092	3,275	3,360

Analysis of Historical Trends and Forecast Outlook, and Management of Cost and Efficiency

From 2007 through to 2011, the Finance and Accounting department has successfully managed the significant changes and increased compliance requirements associated with accounting policy, financial reporting, provincial sales taxes, financial support for the Company's capital expenditure program, financial support for regulatory filings, internal control on financial processes, audit processes, actuarial reporting and treasury activity associated with raising debt to finance rate base and expects to see a similar level of activity over the 2012 and 2013 period. The Finance and Accounting department manages these business challenges by embedding much of the knowledge and related skill set with the employees, however due to various compliance requirements the department must still incur costs with third parties

Non labour charges primarily consist of consulting and contractor costs, as well as bank service charges. Consulting and contractor expenses consist of fees paid to auditor and actuaries, as well as rating agency fees and trustee costs which have increased as the Company's volume of rated domestic market long-term debt has increased to finance rate base.

Despite the significant changes in accounting and compliance requirements from 2007 through 2011, the Finance and Accounting department staffing has remained relatively consistent at approximately 18 to 19 FTEs, and is expected to remain so for 2012 and 2013,. During this time period, including 2012 and 2013, the Finance and Accounting Department O&M Expenses are averaging an annual increase of approximately 3 percent which is generally consistent with inflationary increases.

4.3.4.16 TRANSPORTATION SERVICES

Business Responsibilities

FortisBC Fleet Services has three main functions, Asset Management (vehicle planning and acquisition), Operating & Maintenance, and Support (training, accident investigations, advice and consultation on fleet matters). There currently are 14 full time employees (including ten Licensed Journeyman Mechanics) and 350 units (vehicles and equipment) in the fleet. Vehicle types include heavy commercial vehicles (47), service vehicles (88), passenger/light duty vehicles (119), trailers (43), and specialty equipment and off-road vehicles (53). 287 units are owned, and 63 are leased. The Company leases some vehicles where the need for a vehicle is for a limited time only such as for a specific project that has a specified life.

The FortisBC Fleet department strives to provide vehicles/equipment that are safe and reliable in order to perform the work that they were intended to do, while remaining compliant with all legal regulations and standards (Motor Vehicle Act, National Safety Code, Occupational Health and Safety, etc.) at the lowest possible cost. The goal is to maximize vehicle utilization and minimize lost productivity due to vehicle downtime.

FortisBC outsources some of the routine and minor maintenance work on service trucks and automobiles as well as all body work and painting. This allows the Fleet department to concentrate on maintenance, repairs and overhauls of specialized heavy duty equipment and related safety/compliance inspections.

Business Issues / Challenges

FortisBC's fleet travels nearly five million kilometres per year and consumes approximately 900,000 litres of gasoline and diesel per year. The main challenges are the ability to complete the jobs in challenging terrain, on time, at the lowest possible cost, while trying to lower the Company's carbon footprint.

To counter rising fuel costs and in support of the BC Energy Plan, FortisBC currently has eight low emission hybrid vehicles (six passenger vehicles, one half-ton truck, and one line truck).

FortisBC continues to evaluate and monitor new green vehicle technologies. In concert with FEI, FortisBC is also currently investigating the economics of using natural gas powered vehicles.

Table 4.3.4.16 Transportation Services O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	Total Number of Units in Fleet	329	351	342	348	350	350	352
1.1	Full Time Equivalents	14	15	15	15	14	12	12
		($000s)						
2.0	Expenses							
2.1	Labour	1,550	1,599	1,603	1,562	1,616	1,390	1,410
2.2	Non Labour	3,491	3,547	2,917	2,994	3,269	3,408	3,453
2.3	Recoveries	(4,345)	(4,159)	(3,876)	(4,178)	(4,119)	(4,225)	(4,270)
TOTAL O&M EXPENDITURE:		696	987	644	377	766	573	593

Analysis of Forecast O&M Expenditure and Cost Drivers

After two years of relatively stable fuel prices, 2011 has seen a sharp rise in gas and diesel prices. Declining supply, high consumption, and reliance on inventories are all seen as factors in current fuel prices. The US Energy Information Administration (EIA) forecasts that the average price of fuel will rise by 40 percent in 2011. The price is expected to level off and remain fairly stable through 2013.

Analysis of Historical Trends and Forecast Outlook

While labour costs have steadily risen, overtime costs have been trending down since 2007, from over $0.3 million in 2007 to just over $0.1 million in 2010. Lease costs have a similar pattern, and have fallen over $0.2 million since 2007. The Company expects these trends to continue.

To maintain a high level of safety, compliance and reliability, costs such as tires, maintenance, and insurance expenses have remained relatively consistent on a per fleet unit basis since 2007.

With the exception of fuel, the majority of the fleet department's forecast 2012 and 2013 O&M budget amounts are constant, or have only a moderate increase compared to previous, historical figures.

The Transportation Services Recoveries are charges to capital or to third parties when a fleet unit is used for those types of work. Workers charge the project or customer with the number of hours the fleet unit was used and the credit is applied to Transportation Service O&M costs.

The overall 2012 budget expenditures are expected to decrease by 25 percent from 2011 levels, and the 2013 budget expenditures are expected to increase by 3 percent over 2012.

Management of Cost and Efficiency

Moving forward, FortisBC plans to concentrate its skilled workforce on maintenance, repairs and mandatory inspections of heavy equipment fleet, specialty units, and man lifts. The Company utilizes an AVL GPS (Automated Vehicle Location Global Positioning System) system, which will enable management to monitor and optimize fleet utilization.. Over time, the system is expected to lower fuel and consumables costs (lower speeds, and less idle time) while increasing safety and customer satisfaction (lower speeds, increased efficiencies, lower response times).

4.3.4.17 SUPPLY CHAIN MANAGEMENT:

Business Responsibilities:

Supply Chain Management (SCM) is responsible for the full range of processes that manage the flow of goods and services, as well as information and dollars, between suppliers, customers, and end users. The processes encompassing SCM include the purchasing of materials and services, warehousing, materials management, inventory control and hazardous waste management. The SCM team is comprised of two departments:

Purchasing and Contracts

The Purchasing and Contracts department is responsible for the timely, ethical purchasing of the appropriate materials, equipment, goods, and services required to meet the internal operational, project and strategic obligations of the Company. Transactions for purchasing materials and/or services may include corporate credit cards, purchase orders or complex contracts in accordance with corporate policy.

The Purchasing and Contracts department is also responsible for ensuring that high risk contractors performing services on FortisBC work sites are pre-qualified to meet and maintain the following criteria:

- Technical capability;

- Appropriate safety capability training;
- Sufficient financial stability;
- Sufficient insurance coverage; and
- Appropriate environmental considerations.

Material Services

The Material Services department manages the inventory and performs the physical movement of materials and equipment into the supply chain and from the warehouse to districts or project lay down sites. The Material Services group also manages hazardous waste for the Company including:

- Management of the Hazard Waste Facility in Warfield;
- Handling, transportation and testing of field equipment;
- Coordination and pick up of material with salvage/decommissioning contractors; and
- Maintaining the hazardous waste records.

Business Issues / Challenges:

Due to the level of capital expenditures over the last five years, there have been significant challenges faced by the SCM group in meeting material and equipment delivery requirements. By integrating SCM and operations personnel, planning efforts continue to be a team approach to mitigate risk to the Company as a result of demanding material and equipment requirements.

Unique challenges also exist in procuring major equipment and components considering commodity pricing, foreign exchange, overall marketplace supply and demand and compliance to legislative changes. Keeping ahead of these challenges requires consistent monitoring and trending of market pricing and changing legislation.

Table 4.3.4.17 Supply Chain Management O&M Cost Summary (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
1.0	Full Time Equivalents	21	23	25.5	26	27	24	24
		($000s)						
2.0	Expenses							
2.1	Labour	1,761	1,993	1,609	1,850	2,033	2,008	2,005
2.2	Non Labour	878	178	639	80	270	319	317
2.3	Recoveries	(2,114)	(1,508)	(1,865)	(1,452)	(1,753)	(1,828)	(1,817)
TOTAL O&M EXPENDITURE:		524	664	384	478	550	498	505

Analysis of Forecast O&M Expenditure and Cost Drivers

Unlike the 2007 -2011 period, spending in 2012 and 2013 is expected to focus more on capital sustainment, with fewer large capital projects. This may result in a decrease in the purchase, delivery and handling of larger pieces of material and equipment but is not expected to reduce the overall level of material and equipment being managed. The result will be a higher volume of smaller value inventory being processed.

Analysis of Historical Trends and Forecast Outlook

Commodity prices in the last decade experienced strong increases during the 2006 – 2008 period leading up to the collapse of the United States economy in 2008 – 2009. For the most part, commodity prices and metal prices have recovered and exceed the 2008 levels. Future price increases are unclear, but with a combination of a general economic recovery in the United States beginning to gather momentum, increasing fuel prices, increasing demand from Asia including the rebuilding taking place in Japan, the expectation is that commodity prices will continue to rise. The Purchasing and Contracts group will therefore be monitoring market pricing and trends and where possible entering into strategic sourcing agreements with suppliers in order to mitigate the impact of commodity price increases.

Supply Chain Recoveries refer to a material handling charge that is included in the cost of each item that is issued from inventory. The charge is to recover the cost of labour and expenses associated with warehousing.

Management of Cost and Efficiency

As noted earlier the Supply Chain group looks for opportunities to reduce costs or increase efficiencies on an ongoing basis. The elimination of a leased warehouse in Kelowna in favour of centralized warehousing is discussed in Tab 6, 2012-13 Capital Plan. Options that are being explored to increase efficiencies include:

- Utilizing consignment inventory – the Company has been able to enter into an agreement with a transformer vendor where the vendor supplies the Company with 50 "safety stock" transformers that are inventoried at FortisBC sites, but are not paid for until the Company uses the transformer.
- Vendor managed inventory – the Company is also investigating the use of vendor managed inventory for some times of stock items in order to reduce the Company's warehousing requirements.
- The application of bar coding technology in order to receive, manage and track inventory more efficiently and with minimal data entry.

4.3.4.18 CORPORATE & EXECUTIVE MANAGEMENT

Transfer Pricing Policy and Code of Conduct

FortisBC's Code of Conduct (COC) and Transfer Pricing Policy (TPP) were updated in 2009 and approved by the Commission in Order G-5-10A as part of the Commission's review of the Subcontractor Agreement between FortisBC Inc. and FortisBC Pacific Holdings Inc. (FPHI).

FortisBC proposes no changes to the existing COC and TPP. Both policies are expected to continue to provide appropriate direction and rules to govern the interaction of FortisBC and Affiliate Non-Regulated Businesses during the period of the current Application. FortisBC believes that the processes in place and the independent compliance reviews conducted annually by FortisBC's Internal Audit have been effective in providing a sufficient level of assurance to ratepayers, stakeholders and the Commission.

In conclusion there are significant positive benefits of contracting FortisBC personnel to FPHI under the provisions of the COC and TPP, both in terms of incremental revenue to the regulated utility and labour force enrichment.

Sharing of Services with FortisBC Energy Inc.

In the summer of 2010, FortisBC and the FEI began sharing a common executive management team. This structure allows for sharing of specialized resources and economies of scale for customers. Currently FortisBC is charging FEI for those executives who are FortisBC employees and have responsibilities in FEI, and is receiving charges for FEI executives who have responsibilities at FortisBC. Additionally, certain FortisBC employees, other than the executive, perform work for FEI and certain employees in FEI provide services to FortisBC. Currently, the cross charges to and from FEI include a fully loaded wage plus an overhead charge of 5.5 percent. The profit margin of 10 percent pursuant to the COC and TPP is not being charged as these are two regulated companies. The Company believes that the sharing of resources between companies that are regulated by the BCUC on a cost recovery basis is in the public interest and no compensation for profit is necessary.

In order to further streamline this process between similar BCUC regulated entities, FortisBC and FEI are proposing to simplify the cross. In this Application, mirroring the proposed treatment in FEI's 2012 – 2013 Revenue Requirements and Rates Application, FortisBC is requesting that charges between these regulated entities be based on a fully loaded wage but to not include an overhead charge.

The Corporate and Executive Management includes the costs for insurance, Board of Directors (Board), Fortis Inc. corporate services, other corporate initiatives and executive costs.

Total Corporate costs are outlined in Table 4.3.4.18-1 below:

Table 4.3.4.18-1 Total Corporate Costs (2007-2013)

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
	($000s)						
Insurance	1,570	1,527	1,581	1,539	1,393	994	1,449
Board of Directors	365	369	373	289	268	271	275
Fortis Inc. Corporate Service Costs	652	830	919	1,283	1,494	1,538	1,585
Corporate Other	(492)	146	730	(576)	635	-	-
Executive	2,352	2,372	2,523	2,515	2,282	2,309	2,365
Total Corporate	**4,447**	**5,244**	**6,126**	**5,050**	**6,072**	**5,112**	**5,674**

Insurance

Insurance costs are outlined in Table 4.3.4.18-2 below:

Table 4.3.4.18-2 Total Insurance Costs (2007-2013)

		2007A	2008A	2009A	2010A	2011F	2012F	2013F
					($000s)			
Premiums	(1)	1,395	1,294	1,211	1,159	1,211	1,272	1,335
Asset Valuation	(2)	-	53	-	-	-	60	-
FortisBC Holdings Advisory Services	(3)	-	5	5	5	7	8	8
Self Insurance Reserve Expense	(4)	175	175	365	375	175	-	-
First & Third Party Liability Expenses	(5)	-	-	-	-	-	101	106
Refund of Self Insurance Reserve	(4)						(447)	
		1,570	1,527	1,581	1,539	1,393	994	1,449

FortisBC maintains insurance coverage through a program coordinated by its parent company, Fortis Inc., including liability, all risk property, boiler and machinery, non-owned aircraft and directors' and officers' liability insurance. FortisBC self-insures against the risk of damage to transmission and distribution poles, wires and related equipment. FortisBC also maintains insurance coverage that is required by provincial statute, which covers automobile liability and a government fire suppression expense. The coverage amounts and terms of the Corporation's insurance agreements are consistent with industry practices.

FortisBC's insurance expense does not include any internal labour costs as the related administration is incurred by the Company's Finance department. The more complex insurance advisory services are provided by FortisBC Holdings Inc., which are included in the insurance costs.

Insurance expense is expected to decrease from the 2007 level of $1.6 million to approximately $1.4 million in 2013.

(i) Insurance Premiums

Insurance premiums are subject to varying non-controllable market conditions; however insurance premiums from 2007 through to 2013 have been positively impacted by the economies of scale achieved with the consolidated Fortis group of companies.

Favourable insurance market conditions in 2008 resulted in the stabilization or reduction of insurance premiums through to 2010. Property coverage premiums had previously experienced upward pressure due to the Company's increased insurable assets replacement values resulting from increased commodity prices. In 2008, the decline in global financial markets also decreased labour and primary construction material prices and as a result, FortisBC was subject to a decrease in replacement values and a corresponding reduction in property insurance premiums. While FortisBC's customers have benefited from the softer market cycle in recent years through decreased insurance premiums, the insurance markets which are impacted by global events are out of the Company's control.

FortisBC's customers have also benefited from lower insurance premiums partially due to the economies of scale obtained with the consolidated Fortis group of companies (the Fortis Group). The specific cost savings cannot be reasonably quantified without going to all the various markets with a complete underwriting submission specifically prepared for FortisBC on a standalone basis, however it should be recognized that such savings are embedded in the historical and forecast insurance premium expense. The benefits of participation in the Fortis Group insurance program include pooling of a geographically spread risk, access to specialized markets, reduced broker fees, reduced administration and reduced insurance premiums.

Forecasting precise insurance premium renewal terms for 2012 and 2013 is difficult due to the potential volatility in market conditions. Insurance market conditions can change due to global events such as large earthquakes, hurricanes, tornadoes or other large losses, therefore insurance premiums are largely uncontrollable. Finally, in prior years, underwriting losses were highly subsidized by strong investment returns; however, in recent years, returns have declined putting additional pressure on premiums.

Each year, the Fortis Group reviews its coverage in light of new forms of coverage and changes in the Company's risk profile and changes in industry standards.

FortisBC has assumed a 5 percent increase in insurance premiums for each of 2012 and 2013.

(ii) Asset Valuations

Every year, an evaluation of the Company's assets replacement value is required for determination of property insurance premiums and this is supplemented by a periodic external valuation. An update to the 2008 valuation of the Company's hydroelectric plants is forecast to occur in 2012 at an estimated cost of $60,000.

(iii) FortisBC Holdings Advisory Services

Beginning in 2008, FortisBC Holdings, the parent company of FEI filled the role of providing certain specialized advisory services to FortisBC on more complicated insurance matters that FortisBC did not have available in house. These services are similar to those provided to FEI and are another example of sharing specialized resources and achieving economies of scale for customers. The advisory services are forecast to increase marginally in 2012 and 2013 over

2011 to $8,000 each year. With insurance expertise available from FortisBC Holdings, the Company can access these advisory services on an as needed basis, rather than incurring the annual costs for full time insurance staff.

(iv) Self Insurance Reserve

FortisBC's insurance expense has also included an annual Self Insurance Reserve (SIR) expense to build up a provision. The SIR provision is then reduced by the actual costs incurred relating to smaller first and third party claims, which include theft and damages. The SIR expense has been used to mitigate the risks associated with the ownership and operation of the transmission and distribution segment of the business which is not insurable. Over the last several years, the SIR provision balance has exceeded the actual first and third party claims and grown to approximately $0.4 million. FortisBC is proposing to return the reserve balance of $0.4 million to customers in 2012.

(v) First and Third Party Liability Expenses

In absence of a SIR provision available for 2012 and 2013, the Company has forecast the costs of first and third party claims based on an average of the historical actual amounts over the last several years.

(vi) Insurance Expense Variance Deferral Account

Insurance expenses may differ from the levels forecast, primarily due to changes in economic factors outside of the Company's control as well as the rise in copper wire theft, for which the future impact is unpredictable. Global events can influence insurance expense and the impact of this type of event cannot be reasonably incorporated into insurance forecasts, therefore a deferral account to capture the difference between actual and forecast insurance expense, including first and third party liability, is requested. For purposes of the 2012 and 2013 revenue requirement, any additions to this rate base deferral account would be included in deferred charges and an amortization term of any accumulated variances will be proposed as part of the 2014 RRA.

Board of Directors

Board of Director costs are outlined in Table 4.3.4.18-3 below:

Table 4.3.4.18-3 Board of Director Costs

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
Number of Board of Members	10	10	9	11	12	12	12
	($000s)						
Board Costs	365	369	373	289	268	271	275

The Board of Director costs include the costs relating to the corporate governance of the Board, the Audit and Risk Committee and Governance Committee (Committees). The majority of the Board is comprised of independent directors.

The Board and its Committees provide a key corporate function to FortisBC which include the following: ensuring the continuous disclosure and governance activities required by external regulators and stakeholders and third parties are appropriately carried out, providing oversight over the corporate activities of the Company, and developing and maintaining governance procedures and policies.

Prior to July 1, 2010 FortisBC had a separate Board and Committees and incurred 100 percent of the costs. Effective July 1, 2010 the Board of Directors is a joint Board that is shared with amongst FortisBC and the FEU. All costs incurred for compensation and certain other Board and Committee expenses are shared between FortisBC and the FEU based on a Massachusetts Formula[4] applied to revenue, payroll and net tangible assets. This allocation methodology has previously been approved by the BCUC for the FEU. Based on this methodology of allocating costs, FortisBC has forecast an allocation of 23.35 percent of the shared FortisBC Utilities Board and Committee compensation and expenses for 2012 and 2013.

Since 2007, the number of Board members has increased from ten to twelve members and is forecast to stay at twelve for 2012 and 2013. The costs associated with the Board averaged approximately $0.37 million for each of the years 2007 through 2009. The decrease in costs in 2010 was due to the sharing of Board fees and certain other Board costs amongst the FortisBC group of Companies effective July 1, 2010. Although the decrease in costs due to the sharing has been partially offset by increased travel costs for both Board and executive attending the Board meetings and related functions, the costs in 2012 and 2013 are forecast to be less than those incurred in each of the years 2007 through 2010.

[4] The Massachusetts Formula is in extensive use in industry and is comprised of the arithmetical average of operating revenue, payroll, and the average net book value of tangible capital assets plus inventories. The use of these factors represents the total activity of all business segments as a means to allocate costs that cannot be directly assigned.

Fortis Inc. Corporate Service Costs

The Company shares certain specialized services that reside in Fortis Inc. and provide expertise to the Fortis Inc. subsidiaries including FortisBC. These services are shared amongst the Fortis Group, thereby providing economies of scale to FortisBC. The appropriateness of the Fortis Inc. services were reviewed by KPMG in a report to Terasen Gas Inc. (now FEI) in 2009 and assessed as to whether:

- The services were operationally necessary;
- If the methodology used to allocate the costs was reasonable; and
- If the allocated costs were reasonable as compared to market.

A copy of the report was included in the Terasen Gas Inc. 2010 and 2011 Revenue Requirements and Delivery Rates Application and the Fortis Inc. costs were applied for and approved by Commission Order G-141-09 for FEI in 2009.

The key services performed by Fortis Inc. are strategic, corporate governance in nature, provide access to the equity capital markets and furnish equity funding of the utility. They consist of the following functions:

- Executive (CEO and CFO) - provide strategic leadership, leadership and management for Fortis Inc., manage the organizational structure, financial planning, maintaining controls and internal systems, employee relations, external communication, board relations, regulatory compliance, provision of legal services, maintain internal and external audit activities, and corporate financing and budgeting.
- Treasury and Taxation - perform Fortis Inc. treasury services and provides oversight to subsidiary companies for debt and equity financings, maintaining the capital structure, corporate cash management and forecasting, preparation of corporate tax returns, tax planning, coordinating corporate tax audits, rating agency process, and corporate credit facilities.
- Investor Relations - manage analyst, investor and shareholder communications, coordinate Fortis Inc. annual general meeting, preparation of quarterly investor relations reports, manage public and media relations, maintain Fortis Inc. website, manage dividend reinvestment and share purchase plans, and oversight over the Annual Report preparation process.

- Financial Reporting - preparation of monthly, quarterly and annual consolidated and non-consolidated Fortis Inc. financial statements, coordination with external auditors, analysis of financial information, preparation of the Annual Information Form for Fortis Inc., Annual Report for Fortis Inc., quarterly and annual Management Discussion and Analysis for Fortis Inc. and other continuous disclosure documents for Fortis Inc., coordinate consistent accounting policy treatment across the Fortis Group, oversight and coordination of conversion to IFRS and USGAAP, preparation of the company-wide quarterly forecast consolidated earnings for Fortis Inc. and earnings per share and maintaining internal controls over financial reporting for Fortis Inc.
- Internal Audit - performs Fortis Inc. internal audit activities, provides oversight over the internal audit function at the Fortis subsidiary companies, administers and monitors reports of allegations of suspected improper conduct or wrong doing, development of a company-wide ERM program approach.
- Corporate Secretary Board of Directors - annual strategic planning and risk management activities, selecting and evaluating the CEO, appoint officers, review and approve all material transactions, evaluate Fortis Inc.'s internal controls relating to financial and management information systems, establish and maintain policies regarding communication and disclosure with stakeholders, develop and maintain governance procedures.
- Although Fortis Inc. incurs costs in support of the utilities; some operating costs are unique to the holding company and are not passed on to its subsidiaries. These excluded costs are:
    - All identifiable Corporate Development costs relating to potential or completed acquisitions;
    - Costs associated with non-regulated entities; and
    - 50 percent of all compensation to the President & CEO, VP Finance & CFO and Manager, Treasury as an estimate of their effort related to business development activities.

In addition, as required under Commission Order G-52-05, all stock option costs have been excluded from regulated costs.

Beginning in 2008, Fortis Inc. began allocating its recoverable costs to FortisBC based on the relative assets by subsidiary as it is closely correlated to the net investment by Fortis Inc. in the respective subsidiaries. The actual and forecast costs allocated to FortisBC are contained in Table 4.3.4.18-4 below.

Table 4.3.4.18-4 Fortis Inc. Actual and Forecast Costs Allocated to FortisBC

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
	($000s)						
Fortis Inc. Corporate Service Charges	652	830	919	1,283	1,494	1,538	1,585

The increase in allocated costs is attributable primarily to the increase in FortisBC's asset base relative to the Fortis group of companies, inflation over the period and the loss of sundry income from the rental of poles at Fortis Inc. effective January 1, 2011.

The eligible cost estimates for allocations to FortisBC for 2012 and 2013 are summarized in Table 4.3.4.18-5.

Table 4.3.4.18-5

	2012	2013
	($000s)	
Executive Function	579	614
Treasury Function	65	68
Investor Relations Function	209	219
Financial Reporting Function	238	236
Internal Audit Function	21	22
Board of Directors	234	246
Other	389	377
Subtotal	1,735	1,782
Less: Fortis Properties Management Fee Revenue	(197)	(197)
Total	1,538	1,585

FortisBC customers benefit from the efficiencies realized by allocating appropriate Fortis Inc. costs across its subsidiaries. The cost to FortisBC for the services received from Fortis Inc. would be higher on a stand-alone basis. In addition, FortisBC and its customers benefit from the level of expertise at Fortis Inc. that would not be available on a stand-alone basis for the same or similar cost.

In this application, FortisBC is applying for the same treatment and proportionate allocation of Fortis Inc. costs that were applied for and, received approval for by FEI, in 2010-2011.

Corporate Other

Corporate Other costs are summarized in Table 4.3.4.18-6 below:

Table 4.3.4.18-6 Corporate Other Costs

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
	($000s)						
Corporate Other	(492)	146	730	(576)	635	-	-

Corporate Other costs vary from year to year. The expenditures in this account generally include those of a more confidential and/or one time project nature. The 2007 and 2010 balances include recoveries of executive time working on non-regulated activities. These activities were charged out in accordance with the FortisBC COC and TPP.

No expenditures and/or recoveries are forecast for 2012 and 2013.

Executive

Executive costs are summarized in the Table 4.3.4.18-7 below.

Table 4.3.4.18-7 Total Executive Costs

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
Executive Officers Directly Paid by FortisBC	6	6	6	6	5	5	5
Total Executive Officers Including Shared Officers	6	6	6	10	10	10	10
Number of Administrative Staff	2	2	2	2	2	2	2
	($000s)						
Operating Labour Costs for Officers Directly Paid by FortisBC	2,289	2,410	2,622	2,734	2,642	2,686	2,735
Executive - Shared Services Recoveries (net)	(100)	(228)	(212)	(404)	(711)	(740)	(740)
	2,189	2,182	2,410	2,330	1,931	1,946	1,995
Expenses	163	190	113	185	351	363	370
Total Executive	**2,352**	**2,372**	**2,523**	**2,515**	**2,282**	**2,309**	**2,365**

The executive of FortisBC provide the leadership for the Company. The operating labour costs for officers directly paid by FortisBC consist primarily of wages and benefits. The number of executive was held at six for the period 2007 through to June 30, 2010. As described in the beginning of Section 4.3.4.17, in the summer of 2010, FortisBC and the FEI began sharing a common executive management team. This resulted in the number of executive officers increasing to 10 effective July 1, 2010. This structure allows for sharing of more specialized resources and economies of scale for customers. The Company benefits from the expertise of a broader depth of experience of 10 officers for less cost than the six officers employed previously. The sharing of executive responsibilities between the entities facilitates the companies cross charging each other for the time each executive expects to spend with their cross over responsibilities. Currently FortisBC is charging FEI for those executives who are FortisBC employees and have responsibilities in FEI, and is receiving charges for FEI executives who have responsibilities at FortisBC. Currently, the cross charge to FEI includes a fully loaded wage plus an overhead charge of 5.5 percent. The forecast years 2012 and 2013 do not include the overhead charge of 5.5 percent for recoveries from FEI. The elimination of the overhead charge is discussed in the beginning of Section 4.3.4.17 of this Application.

FortisBC also provides executive leadership over the legal department of FortisBC Holdings Inc. since 2007. The recoveries are based on time and are recovered in accordance with the COC and TPP.

The sharing of executives amongst the FortisBC Utilities is forecast to result in a net recovery of approximately $0.7 million during the period 2011-2013.

In the first quarter 2011 one FortisBC directly paid executive officer retired and one shared executive officer was added as an officer of FortisBC. Administrative Assistants have remained at two for the period 2007 through 2013.

Operating labour costs for officers directly paid by FortisBC in 2012 are relatively consistent with 2011 as salary escalations of three percent have been largely offset by reduced benefit loadings and the retired executive. Operating labour costs for officers directly paid by FortisBC in 2013 are increasing 1.8 percent over 2012 due to a three percent labour escalation being partially offset by reduced labour loadings.

Expenses have increased in 2011 over 2010 primarily due to inflation, an increase in the amount of required travel, and increased telecommunications costs. Expenses during 2012-2013 are increasing primarily due to inflation.

Overall total executive costs in 2013 are only $13,000 higher than those incurred in 2007, effectively flat in nominal dollars and declining in real terms and on a cost per customer basis. The sharing of executive across related companies has resulted in a significant savings to customers through economies of scale.

4.4 CAPITALIZED OVERHEAD

In its 2006 Revenue Requirements Application, which proposed a PBR plan, the Company introduced a new mechanism for allocating indirect overhead costs to capital expenditures based on the principles of activity based costing, including indirect overhead costs not previously allocated to capital expenditures. The methodology suggested that 25.2 percent of Gross O&M Expense should be Capitalized Overhead. Parties to the 2006 NSA (approved by Order G-58-06) agreed to set Capitalized Overhead at 20 percent of Gross O&M Expense for the term of the PBR plan. The parties also agreed to review the methodology at the end of the PBR term.

The Company has updated the methodology to reflect 2010 actual financial results and cost drivers. Based on actual 2010 Gross O&M, the methodology suggests a 23.9 percent Capitalized Overhead rate ($11.019 million of Capitalized Overhead on actual total Gross O&M Expense of $46.148 million). A description of the various loadings and methodology follows.

For the operating business units; Generation, Network Services, and Customer Service, the identification of costs that support capital work is generally straightforward and where possible such costs are charged directly to a capital project. Where an activity supports multiple projects, costs are estimated during the budgeting process and a direct overhead loading rate is used to distribute those costs amongst those projects. Generation costs are allocated to capital and third-parties using an absorption costing method. Finally, where appropriate, some corporate overhead costs are charged directly to a capital project. For example, where a purchaser is assigned to a capital project team to provide purchasing support, those costs are charged directly to the project.

The estimate of a corporate overhead loading rate is developed through a three-step process.

First, for each corporate department a cost "driver" is identified that is most closely tied to the level of effort of support it provides the operating business units. This allocation is then collected in a loading pool for each business unit.

The drivers are: average number of Generation, Network Services and Customer Service employee count in 2010*;* relative risk associated with the business units; relative effort representing approximate time spent supporting each business unit; total corporate services expenditures (total expenditure on operating, capital and third party), and allocations based on management's best estimates.

The corporate functions, their drivers and the resulting allocations for 2010 are summarized in the following table.

Table 4.4-1 Determination of Corporate Support Levels by Operating Unit (2010)

		Driver Split				Percent Allocated to		
Department	Driver	Total	Generation	Network Services	Customer Service	Generation	Network Services	Customer Service
Human Resources	Employee Count	400	95	236	69	23.8	59.0	17.3
Internal Audit	% Risk	100	33	33	33	33.3	33.3	33.3
Legal & Regulatory	% Effort	100	33	33	33	33.3	33.3	33.3
Board of Directors	Total Expenditure ($000s)	193	35	149	9	17.9	77.5	4.6
Insurance	Total Expenditure ($000s)	193	35	149	9	17.9	77.5	4.6
Fortis Inc. Corporate Service Costs	Total Expenditure ($000s)	193	35	149	9	17.9	77.5	4.6
Environmental	% Risk	100	50	50	-	50.0	50.0	-
Health & Safety	Employee Count	400	95	236	69	23.8	59.0	17.3
Facilities Management	Employee Count	400	95	236	69	23.8	59.0	17.3
Communications	% Effort	100	20	30	50	20.0	30.0	50.0
Community and Aboriginal Affairs	% Effort	100	10	45	45	10.0	45.0	45.0
Finance & Accounting	Total Expenditure ($000s)	193	35	149	9	17.9	77.5	4.6
Procurement	Total Expenditure ($000s)	193	35	149	9	17.9	77.5	4.6
Executive Management	% Allocation	100	29	35	36	29.0	35.0	36.0
Information Technology	% Allocation	100	20	40	40	20.0	40.0	40.0

* Minor differences due to rounding

Next, the departmental costs are allocated to the operating business units based on the corporate support allocations determined in step one. For example, Human Resource effort is generally proportionate to the number of employees in the departments it supports; based on the employee count in the operating business units, Human Resources costs of $1.638 million (shown in Table 4.4-2 following) are allocated 23.8 percent (95 of 400 employees) or $0.389 million to Generation, 59.0 percent or $0.966 million to Network Services and 17.3 percent or $0.283 million to Customer Service.

Finally the relative proportions of capital-related work (capital intensity) for 2010 in the operating business units are determined based on the relative labour hours charged to O&M Expense versus capital in 2010. The capital intensities of the operating business units are: 75 percent for Generation, 59 percent for Networks Service, and 13 percent for Customer Service. For example, of the $0.389 million of Human Resources costs representing support to Generation, 75 percent or $0.292 million would relate to capital work. The balance, $0.097 million, remains in the Human Resources department as O&M Expense. In total, of the $1.638 million of Gross O&M Expense, $0.899 million was allocated by way of capitalized overhead.

In total, as illustrated in Table 4.4-2 in 2010, approximately 52 percent or $11.019 million of the $21.057 million gross corporate overhead expense would be allocated to capital through the work of the business units, and the balance will remain as Net Corporate O&M Expense.

Table 4.4-2 Application of Unit Factors to Calculate Capitalized Overhead (2010)

Department	2010 Actual Gross O&M Expense	$ Allocated to Generation	$ Allocated to Network Services	$ Allocated to Customer Service	times Capital Intensity Generation 75%	times Capital Intensity Network Services 59%	times Capital Intensity Customer Service 13%	Capitalized Overhead
Human Resources	$ 1,638	$ 389	$ 966	$ 283	$ (292)	$ (570)	$ (37)	$ (899)
Internal Audit	360	120	120	120	(90)	(71)	(16)	(176)
Legal & Regulatory	1,451	484	484	484	(363)	(285)	(63)	(711)
Board of Directors	289	52	224	13	(39)	(132)	(2)	(173)
Insurance	1,539	276	1,193	70	(207)	(704)	(9)	(920)
Fortis Inc. Corporate Service Costs	1,283	230	995	58	(172)	(587)	(8)	(767)
Environmental	241	120	120	-	(90)	(71)	-	(161)
Health & Safety	486	115	287	84	(87)	(169)	(11)	(267)
Facilities Management	3,700	879	2,183	638	(659)	(1,288)	(83)	(2,030)
Communications	1,067	213	320	534	(160)	(189)	(69)	(418)
Community and Aboriginal Affairs	571	57	257	257	(43)	(152)	(33)	(228)
Finance & Accounting	2,615	468	2,028	119	(351)	(1,196)	(15)	(1,563)
Procurement	478	86	371	22	(64)	(219)	(3)	(286)
Executive Management	2,515	729	880	905	(547)	(519)	(118)	(1,184)
Information Technology	2,824	565	1,130	1,130	(424)	(666)	(147)	(1,237)
	$ 21,057	**$ 4,783**	**$ 11,557**	**$ 4,716**	**$ (3,587)**	**$ (6,819)**	**$ (613)**	**$ (11,019)**

* Minor differences due to rounding

From the table below it can be seen that over the period 2007 to 2011(Forecast) gross capital expenditures ranged from $95.2 million to $143.7 million and averaged approximately $121.0 million per year. For the 2012 – 2013 forecast period the Company expects gross capital expenditures to average approximately $117.8 million per year.

Table 4.4-3 Gross Capital Expenditures (2007-2013)

	2007A	2008A	2009A	2010A	2011F	2012F	2013F
				($ millions)			
Total Gross Expenditure	143.7	111.6	112.7	142.0	95.2	105.7	129.9
Average 2007 - 2011 Inclusive					121.0		
Average 2012 - 2013 Inclusive							117.8
Average 2007 - 2013 Inclusive							120.1

Based on the historical and forecast gross capital expenditures the Company considers that the Capitalized Overhead rate applied to Gross O&M Expense should be maintained at 20 percent over the 2012 and 2013 test period. Using average capital expenditures over time and maintaining a 20 percent Capitalized Overhead rate will serve to mitigate variances to Net O&M Expense and the attendant revenue requirement fluctuations.

4.5 OTHER INCOME

Other Income is revenue other than from the sale of electricity and is derived from the following sources:

Table 4.5 Other Income

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Apparatus and Facilities Rental				
2	Electric Apparatus Rental	3,864	3,070	3,276	3,374
3	Lease Revenue	141	138	108	104
4		4,005	3,208	3,384	3,478
5	Contract Revenue				
6	Waneta Management Fee	380	457	455	464
7	Waneta Management Fee Capital	8	91	77	-
8	Waneta Carrying Costs	94	94	94	94
9	Brilliant Management Fee	208	320	305	273
10	Brilliant Management Fee Capital	280	221	295	205
11	Fortis Pacific Holdings Inc.	592	625	488	279
12		1,562	1,808	1,714	1,315
13	Miscellaneous Revenue				
14	Connection Charges	489	1,038	1,079	1,122
15	NSF Cheque Charges	11	11	11	12
16	Sundry Revenue	162	66	67	69
17		662	1,115	1,157	1,203
18	Transmission Access Revenue	-	1,109	1,098	1,071
19	Investment Income	224	162	128	98
20	Total	6,453	7,402	7,481	7,165

4.5.1 Apparatus and Facilities Rental

Apparatus Rental is primarily pole contact revenue from other utilities and businesses that attach their facilities to the FortisBC system in order to deliver services to their customers. Examples include telephone and cable television providers. Customers are charged a unit rate per pole contact multiplied by the number of poles that they have contacted. Periodic audits are conducted to verify the number of contacts on each pole.

In 2008, a field audit was conducted which resulted in an increase in the number of pole contacts. The audit results were challenged by a customer and a negotiated settlement was concluded in 2010 resulting in an increase in revenues. Actual results in 2010 reflect the audit settlement of $0.358 million as well as retroactive and current billing of $0.853 million for disputed pole maintenance costs.

Rental income in 2011 includes $0.294 million as a result of third party leasing of fibre optic cable on FortisBC transmission poles for a part year. This income is forecast to increase to $0.398 million for 2012 and $0.43 million for 2013 reflecting full year revenue.

A small percentage of revenue is derived from subletting space in the Trail office building. With a softening in the Trail lease market, in addition to a few of the smaller leases expiring over the next few years, revenue is anticipated to decline.

4.5.2 Contract Revenue

The Company operates and maintains a number of facilities for other third party entities. Management Fees represent charges to third party customers for work performed by FortisBC at the Waneta and Brilliant hydroelectric generating facilities.

This third party work and the associated revenue fluctuate based on customer requirements. The Waneta Management Fee Capital is expected to be near the $0.1 million level in 2011 and 2012 but drops to zero in 2013 as there are no capital projects expected at that facility in that year.

The Waneta Carrying Costs represents a charge to Teck for its nominated share of the financing cost of South Slocan, Warfield and System Control Centre facilities under the Waneta Management Agreement.

Similarly, for the Brilliant Management Fee, the anticipated fee fluctuates from $0.305 million in 2012 to $0.273 million in 2013 as the anticipated work will peak in 2012 and slightly decline in 2013. The same is expected for the Brilliant Management Fee Capital revenue, as the magnitude and type of work varies, the anticipated management fee revenue varies.

FortisBC Pacific Holdings Inc. revenue is the transfer price profit on third party contract work conducted by FortisBC on behalf of FortisBC Pacific Holdings Inc. The volume of work, and therefore the transfer price profit, fluctuates based on customer requirements. The City of Kelowna contract expires October 2012 and the Company is not confident the contract will be renewed thereby contributing to the drop in revenue in both 2012 and 2013.

4.5.3 Miscellaneous Revenue

Miscellaneous Revenue is made up of Connection Fees, Non-sufficient funds (NSF) charges and Sundry Revenue. Connection Fees have more than doubled the forecast revenue for 2011 to 2013, as compared to 2010, due to changes to Standard Charges approved by Order No. G-156-09 concerning the 2009 Cost of Service Analysis and Rate Design adjustments. The majority of the sundry revenue is a recovery of costs for service such as street light maintenance charged to municipalities.

4.5.4 Transmission Access Revenue

Transmission Access Revenue represents charges to customers who utilize FortisBC's transmission system to transmit power over the FortisBC system. FortisBC had only one small customer from 2008 to 2010 that was generating minimal power. In 2011 one new customer came online while the other increased its capacity. Both customers are expected to generate estimated combined revenue of $1.1 million per year for 2011 to 2013.

4.5.5 Investment Income

Investment income is primarily DSM loan interest income and foreign exchange gains or losses. The Company is experiencing a decline in the number of DSM loans. Hence, as loans mature a corresponding drop in interest income is expected.

4.6 TAXES

4.6.1 Property Tax

The assessment of all properties in the province of British Columbia is carried out on an annual basis by the BC Assessment Authority, under the authority of the Assessment Act. Provincial legislation in BC requires FortisBC, with properties valued on an ad valorem basis, to report changes in its asset base annually (by October 31). In its simplest form property taxes are a function of Assessment (property valuation) Policy and Taxation Policy. Property Taxes are a function of assessment policy and taxation policy.

4.6.1.1 ASSESSMENT POLICY

Assessment policy is set out in Provincial legislation under the Assessment Act and is primarily concerned with valuation principles and methodologies as well as classification of properties for taxation purposes. Valuation of electrical utility properties is highly dependent on legislated manuals and rates to determine market values. Electrical assets are classed by type/size of transmission and type/location of distribution infrastructures. This data is then segregated by lengths and reported annually.

When new assets are brought on line these assets must be reported to the BC Assessment Authority. If it is necessary, new tax folios may be created and the property valued and classified in accordance with the BC Assessment Act.

Property assessment values for the current tax year reflect the market value at July 1 of the previous year based on the state and condition of the property at October 31 of the previous year.

4.6.1.2 TAXATION POLICY

Tax policy is applied by various taxing authorities under their legislated authority and determines how their budget will be distributed to the various classes of properties through the property tax. Property Taxes payable by FortisBC is categorized into four general categories of taxes as follows:

1. General Taxes: These are typically levied directly by the primary taxing jurisdiction and include municipalities, First Nations, and the Surveyor of Taxes for rural areas.
2. School Taxes: These are levied directly by the Province.
3. Other Taxes: These include all taxes that are levied by other taxation authorities and include levies for BC Assessment, Municipal Finance Authority, Regional Districts, Hospital Districts, etc.
4. Taxes based on Revenues: Section 353 of the Local Government Act requires “utility companies” to pay a portion (currently one percent) of revenues to municipalities in lieu of taxes that would otherwise be paid on improvements specified in legislation other than buildings. For FortisBC, revenues include only revenues earned within the specific municipality related to electricity consumed.

4.6.1.3 CURRENT FORECASTS

Property tax for 2012 and 2013 uses Company forecasts of assessed values of taxable assets, municipal mill rates, and taxes from revenues earned from electricity consumed within the municipalities. The following table provides the forecast Property Tax Expense for 2011-13. It also provides 2010 actual property taxes for the purpose of comparison.

Table 4.6.1.3 Actual and Forecast Property Tax Expense ($000s)

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Generating Plant	2,830	2,925	2,994	3,066
2	Transmission and Distribution	5,590	6,375	6,707	6,994
3	Substation Equipment	3,273	4,067	4,265	4,435
4	Land and Buildings	545	550	566	590
5	Total Property Tax	12,238	13,917	14,532	15,085

Property Taxes in 2011 are forecast to be higher compared to 2010 by approximately $1.68 million (approximately 14 percent) due to additions of new assessable improvements resulting primarily from the Okanagan Transmission Reinforcement (OTR) project which is forecast to be substantially complete in 2011. The forecast 2011 Property Tax expense of $13.92 million, closely matches the 2011 approved amount of $13.94 million.

During 2012-13, Property Taxes are forecast to escalate at an annual average of approximately four percent, primarily attributable to:

- Changes in revenues from electricity expected to be consumed within the municipalities;
- Expected increases to assessment from normal construction;
- Expected inflationary factors applied to legislated rates; and
- Expected changes in tax rates.

4.6.1.4 PROPERTY TAX ASSET VARIANCE DEFERRAL

The BC Assessment Authority is undertaking a review of the valuation of certain electrical system rates for property tax purposes. This review could potentially impact FortisBC and result in a variance from the property tax amounts forecast in 2012 and 2013 in Table 4.6.1.3 above. The Company is seeking a property tax variance deferral account related to the BC Assessment Authority's review of asset valuation, in the event that a review is conducted, as it is largely out of the Company's control and any impact cannot be reasonably forecast at this time. For purposes of the 2012 and 2013 revenue requirement, any additions to this rate base deferral account would be included in deferred charges and an amortization term of any accumulated variances will be proposed as part of the 2014 Revenue Requirements Application.

4.6.2 Income Taxes

FortisBC is subject to corporate income taxes imposed by the federal and BC governments.

The table below provides details of the Company's income tax expense calculated for 2010, the approved 2011 amounts and the forecasts for 2011 through 2013.

Table 4.6.2 Income Tax

		Ref	Actual 2010	Approved 2011	Forecast 2011	Forecast 2012	Forecast 2013
					($000s)		
1	UTILITY INCOME BEFORE TAX		77,975	90,531	94,726	92,723	99,418
2	Deduct:						
3	Interest Expense		35,138	40,505	39,364	41,319	43,553
4	ACCOUNTING INCOME		42,837	50,026	55,362	51,404	55,865
5	Deductions:						
6	Capital Cost Allowance	(a)	52,849	56,903	56,954	61,305	65,958
7	Capitalized Overhead	(b)	9,529	10,777	10,777	10,834	11,159
8	Incentives	(c)	629	2,770	(2,266)	5,416	-
9	Financing Fees	(d)	597	619	594	345	662
10	All Other (net effect)	(e)	3,020	(217)	(36)	1,088	574
11			66,624	70,852	66,023	78,988	78,353
12	Additions:						
13	Amortization of Deferred Charges	(f)	3,695	3,297	3,233	4,468	4,358
14	Depreciation	(g)	38,075	42,201	42,118	46,931	48,870
15			41,770	45,498	45,351	51,399	53,228
16	TAXABLE INCOME		17,983	24,672	34,690	23,815	30,740
17	Federal Corporate Tax Rate	(h)	18.00%	16.50%	16.50%	15.00%	15.00%
18	Provincial Corporate Tax Rate	(h)	10.50%	10.00%	10.00%	10.00%	10.00%
19	Combined Corporate Tax Rate		28.50%	26.50%	26.50%	25.00%	25.00%
20	Income Taxes Payable		5,125	6,538	9,193	5,954	7,685
21	Investment Tax Credit		(27)	-	-		
22	Taxes Payable		5,098	6,538	9,193	5,954	7,685
23	Prior Years' (Overprovisions)/Underprovisions	(i)	(738)	-	61	-	-
24	Deferred Charges Tax Effect	(j)	184	195	186	98	177
25	REGULATORY TAX PROVISION		4,544	6,733	9,440	6,052	7,862
26	Effective Tax Rate	(k)	10.6%	13.5%	17.1%	11.8%	14.1%

The items included in the reference column in the above table are discussed further in Section 4.6.2.3, Determination of Taxable Income.

Income taxes payable have been calculated using the flow-through (taxes payable) method, consistent with Commission approved past practice, at the corporate tax rate of 25 percent for

2012 and 2013. The corporate tax rates used in the RRA are based on the Canada Income Tax Act and the BC Income Tax Act substantively enacted legislation.

4.6.2.1 2010 AND 2011 REGULATORY TAX PROVISION

The Company's tax provision (income tax expense) is expected to increase from approximately $4.5 million in 2010 to a forecast amount of $9.4 million in 2011. The estimated increase in income tax expense from 2010 to 2011 is primarily due to an increase in Accounting Income (Earnings Before Income Taxes), partially offset by a decrease in year over year income tax timing differences and a reduction in the Federal and Provincial income tax rates.

4.6.2.2 2012 AND 2013 REGULATORY TAX PROVISION

The Company's tax provision (income tax expense) is expected to decrease from a forecast of approximately $9.4 million in 2011 to a forecast amount of $6.1 million in 2012. The estimated decrease in income tax expense from 2011 to 2012 is primarily due to a decrease in Accounting Income (earnings before income taxes), an estimated increase in income tax timing differences and a reduction in the federal income tax rates.

The Company's tax provision (income tax expense) is expected to increase from a forecast of approximately $6.1 million in 2012 to a forecast amount of $7.9 million in 2013. The estimated increase in income tax expense from 2012 to 2013 is primarily due to an increase in Accounting Income partially offset by an estimated increase in income tax timing differences.

4.6.2.3 DETERMINATION OF TAXABLE INCOME

FortisBC records its Tax Provision by making the following adjustments between Accounting Income and Taxable Income.

a) Capital Cost Allowance (CCA)

CCA is the amount of tax "depreciation" allowed as a deduction from income in computing income taxes payable under the Income Tax Act. A majority of the Company's assets are depreciated at a rate of 8 percent, in Undepreciated Capital Cost (UCC) classes 17 and 47 which are related to electrical utility assets.

b) Capitalized Overhead

A portion (20%) of gross operating and maintenance expenses are deemed to be capitalized for accounting purposes. While these expenses are deemed necessary to put an item of property, plant and equipment in service for accounting purposes, these costs would normally not be capitalized for tax purposes, therefore these costs have been removed from UCC additions and have been deducted for determination of taxable income.

c) Incentives

The incentive adjustment, including incentives incurred in the current year and the amortization of the prior year's incentive, is recognized in accounting income to ensure that the associated variances under PBR are flowed back to the customer. It is a rate-setting mechanism to flow the variances back to the customer in the subsequent year for setting rates and as such is a non-cash item which does not meet the recognition requirements for tax purposes. Therefore, depending on whether the incentive adjustment is to refund or collect from the customer, the incentive income and amortization of incentives are either added back or deducted from determination of taxable income.

d) Financing fees

Financing fees are those costs incurred to issue long-term debt and for tax purposes are permitted to be deducted over a five year period under the Income Tax Act ("ITA"). The deduction of financing fees for tax purposes is representative of the annual tax amortization of the cumulative debt issue cost balance in a given year.

e) All Other

"All Other" is representative of the net of the following items:

- *Reserves* – primarily related to the change in allowance for doubtful accounts, insurance provisions, inventory obsolescence and other various non-deductible accruals.
- *Cumulative eligible property* – the tax amortization of intangible items, including land right of ways, which are deductible for tax purposes similar to CCA for property, plant and equipment.
- *Interest and penalties* – any amounts resulting from tax return and other assessments which are not deductible for tax purposes.
- *Non-deductible meals* – only 50 percent of meals are permitted to be deducted for tax purposes.
- *Costs of removal* – a portion of certain salvage costs have been forecast to be fully deductible as a period expense for tax purposes and therefore removed from the UCC

additions. The deduction of costs of removal as a period expense for tax purposes is an example where the Company is continuously reviewing tax planning opportunities to mitigate customer rates. This deduction reduced the income tax expense for customers in 2009 by approximately $0.7 million and in 2010 by approximately $0.4 million and was flowed back to customers in determining 2011 RRA. The Company has forecast its 2011, 2012 and 2013 Income Tax Expense using similar tax deductions for certain qualifying forecast costs of removal.

f) Amortization of Deferred Charges

Certain costs are deferred for accounting purposes, however are deducted or added back as a period expense for tax purposes in the year incurred. In the years subsequent to the deduction or add back of these deferred charges for tax purposes, the amortization of the deferred charges is added back for determination of taxable income, similar to the add-back of depreciation of capital assets.

g) Accounting Depreciation

Depreciation for accounting purposes is based on the results of depreciation studies and agreed upon depreciation rates. In the determination of taxable income, the accounting depreciation is added back and the Company is able to deduct the tax depreciation known as CCA. As a result, a timing difference arises from when assets are depreciated for tax and accounting purposes. The Company has a higher rate of depreciation for tax purposes than for accounting purposes, which results in a deferred income tax liability, described further in Appendix E – Accounting Changes and Non-Rate Base Assets (US GAAP).

h) Federal and Provincial Corporate Income Tax rates

The tax rates are substantively enacted, meaning that the proposed legislation to change the tax rate has passed first reading in the House of Commons or provincial legislature for majority governments and third reading for minority governments. These rates are based on information compiled by Ernst & Young from the various governments.

- *Federal Corporate Income Tax Rates* have been reduced from 18.00 percent in 2010 to 15.00 percent in both 2012 and 2013.
- *BC Corporate Income Tax Rates* have been reduced from 10.50 percent in 2010 to 10.00 percent in both 2012 and 2013. This does not contemplate potential reforms to the HST which could potentially result in an increase of 2.0 percent beginning in 2012.

Further details on the potential HST reform and the impact on Corporate Income Tax rates are discussed further in Section 4.6.3.

i) Prior Years' (Overprovision)/Underprovisions

At the end of each fiscal year, the Company estimates its income taxes owing based on a summarized estimate using the best available information at that time. Subsequent to the fiscal year-end, the Company conducts a more detailed tax review and prepares its actual T2 Corporate income tax return to file with Canada Revenue by the deadline of June 30 in the succeeding year. The Prior Years' (over)/underprovisions represents the difference between the estimated income tax owing at the end of the year and the actual filed income taxes owing on the tax return.

j) Deferred Charge Tax Effects

Pursuant to Commission Order G-52-05, the Company records all deferred charges, excluding preliminary and investigative costs which are transferred to capital projects, be treated using a net-of-tax deferral accounting in order to achieve proper matching of costs and benefits. Under the net-of-tax method, any gross additions to deferred charges, to the extent that they are tax deductible, are offset by a tax effect calculated at the prevailing income tax rate for the current year. The deferred charges additions are essentially offset by the tax effects in a given year and therefore are "netted out" on the above tax schedule. The deferred charge tax effects shown in the above schedule relate specifically to debt issue costs, as the tax effects must be recognized over a five year period, similar to the deduction for the debt issue costs themselves pursuant to the federal and Provincial Income Tax Acts.

k) Effective Tax Rate

The effective tax rate refers to the actual tax rate paid, calculated as taxes payable divided by accounting income, versus the statutory tax rate. The effective rate is generally different from the statutory tax rate due to timing differences in the recognition of certain types of income and the deductibility of certain expenses for accounting and tax purposes. These timing differences are primarily related to items that have been capitalized for accounting purposes and expensed for income tax purposes, as well as the difference in depreciation rates for accounting purposes compared to CCA for income tax purposes.

4.6.2.4 REQUEST FOR INCOME TAX VARIANCE DEFERRAL

At any time, the Company can face uncontrollable changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Provincial sales taxes or any other tax that may be imposed. The Company is seeking an Income Tax Variance deferral account to capture and accumulate variances from forecast, as described in Section 4.6.2, resulting from the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies at Federal, Provincial or any other level of jurisdiction. The proposed Income Tax Variance deferral account would also accumulate any required compliance costs, including changes to information systems. During the last six years of FortisBC's PBR term, as approved under BCUC Order No. G-58-06, income tax variances qualified as a Z factor provision resulting from Acts of legislation or regulation of government and were treated in a similar manner for rate-setting purposes. For purposes of the 2012 and 2013 revenue requirement, any additions to this rate base deferral account would be included in the deferred charges schedule and an amortization term of any accumulated variances will be proposed as part of the 2014 RRA.

4.6.2.5 DEFERRED INCOME TAXES

FortisBC follows the taxes payable method of accounting for income taxes on regulated earnings in accordance with BCUC Order G-37-84:

> *"The Commission has found that the public interest will best be served with a change to "flow-through" accounting for income tax purposes for the Applicant. The change is to occur effective August 1, 1984. The balance of deferred income taxes on the books of the Applicant as at July 31, 1984 will remain and be included in the capital structure as zero cost capital."*

In addition, certain regulatory assets and deferred charges are recorded net of their income tax impact, with the offset charged to income tax expense. Under this methodology, customer rates do not include the recovery of deferred income taxes related to temporary timing differences between the tax basis of recording regulated assets and liabilities versus their carrying amounts for accounting purposes, other than for the regulatory assets and deferred charges recorded net of their income tax impacts.

Under Canadian GAAP and US GAAP, the Company is required to record a future income tax liability with a corresponding offset to regulatory assets for amounts expected to be included in approved rates charged to customers in the future, as documented in Appendix E to the 2012-13 RRA.

The deferred income tax liability arises primarily due to the differences between the depreciation rates approved by the Commission for rate setting purposes compared with the rates of depreciation used for the Company's tax calculation purposes. As a result of FortisBC's proposed capital expenditures, the deferred income tax liability is expected to increase in the future due to these tax timing differences.

4.6.2.6 INCOME TAXES SUMMARY

FortisBC will continue to incur income taxes that are imposed by different government bodies and are subject to auditor review. The Company has forecast income tax expense using prudent, reasonable assumptions and similar methodology to prior years. The tax expenses included in this RRA reflect the current substantively enacted legislation and have been properly calculated and applied in calculating the revenue requirement of the Company.

4.6.3 Harmonized Sales Tax

The Company has forecast its 2012 and 2013 Revenue Requirements with the assumption that the 12 percent HST in British Columbia, a single value added sales tax, applies to most of its purchases and transactions.

4.6.3.1 2010 INITIAL IMPLEMENTATION OF HST

On July 23, 2009 the Government of Canada and the Province of British Columbia announced a proposal to harmonize the Provincial Sales Tax (PST) of 7 percent with the Goods and Services Tax (GST) of 5 percent to create a Harmonized Sales Tax with a combined rate of 12 percent, effective July 1, 2010. All legislation related to the implementation of HST was enacted on April 29th, 2010.

Under the new HST legislation, certain goods and services, which were previously subject to PST of 7 percent and not recoverable for tax filing purposes, are instead subject to HST and a full Input Tax Credit (ITC). Over time this would result in a 7 percent savings on costs such as materials, legal fees, office supplies, software licenses, expenses relating to vehicles over 3,000 kg and maintenance contracts for office, computer equipment and software. However, the HST rules also restrict or recapture ITCs for the 7 percent provincial portion of HST on certain expenses which were subject to PST. Therefore, no savings are expected to be achieved on certain telecommunication expenses, passenger vehicle costs and certain energy uses. Meals and entertainment expenses which were not subject to PST are now subject HST and a recapture of ITC on the 7 percent portion of HST, resulting in an increase in these expenses. The harmonization of GST and PST reduced expenses for 2010 and 2011, by an estimated $0.1 million and $0.2 million, respectively. For purposes of this Revenue Requirements Application, the 2012 and 2013 operating and maintenance expenses and capital expenditures have appropriately reflected the impacts of the HST implementation.

Residential Energy Credit

Under the Social Service Tax Act, PST was not applicable to the sale of residential energy. When HST was adopted, residential energy became taxable under the Excise Tax Act. The Residential Energy Credit was implemented July 1, 2010 by the Government of British Columbia in order to provide relief to residential energy users. Suppliers of energy products for residential use in a residential dwelling are required to provide a point of sale credit of the provincial component of HST under the Residential Energy Credit (REC) and Rebate Program. Energy suppliers, including FortisBC, can submit monthly applications to the Ministry of Finance for reimbursement of energy credits provided to eligible customers; the credit provided to customers does not represent a net cost to the Company. Excluding the previously mentioned cost of service savings resulting from the recovery of HST, FortisBC's customers that met the criteria of a residential customer were effectively not impacted by the implementation of HST with respect to commodity taxes on their electricity consumption costs.

4.6.3.2 2011 REMOVAL OR REFORM OF THE HST

On September 13, 2010 it was announced that a referendum on the continuation of the HST will be held in British Columbia on June 24, 2011. The referendum will be held through a mail ballot process with a deadline of July 22, 2011 for voters to return their ballots. The votes will be tallied by Elections BC and the results are expected to be announced in late August. Although the referendum is non-binding, the BC government has pledged that if a simple majority of 50 percent vote against the HST, the tax will be repealed and replaced with the previous PST taxation system.

The BC government announced further HST reform on May 25, 2011 which would reduce the 7 percent provincial portion of the HST rate by two points, should BC residents vote in favour of continuing the HST. The first rate reduction would occur on July 1, 2012 dropping the rate to 6 percent and the second reduction would occur on July 1, 2013 dropping the rate to 5 percent.

The combined HST rate in BC would be reduced to 11 percent in 2012 and 10 percent in 2013. In order to fund the reduction in HST the government will increase the BC provincial general corporate income tax rate from 10 percent to 12 percent on January 1, 2012. The expected increase to corporate income taxes as a result of the BC provincial rate increase would be approximately $0.5 million in 2012 and $0.6 million in 2013.

4.6.3.3 REQUEST FOR HST REMOVAL OR REFORM DEFERRAL ACCOUNT

This 2012-13 RRA has been prepared using assumptions based on the current HST legislation which permits the recovery of HST charged on goods and services by way of ITC, with the exception of certain restrictions previously noted. The HST referendum outcome and resulting decisions are out of the Company's control and we are not able to reasonably forecast the potential resulting effect, if any. Once reasonably determinable or estimable, the Company will bring forth the implications based on the outcome of the HST referendum. If the implications are not known prior to approval of final 2012 and 2013 rates, the Company is requesting approval to capture the related costs in a rate base deferral account for proposed disposition as part of the 2014 RRA. During FortisBC's PBR term, as approved under BCUC Orders G-58-06 and G-193-08, the costs resulting from the initial implementation of HST qualified as a Z factor provision resulting from Acts of legislation or regulation of government and were treated in a similar manner for rate-setting purposes.

4.7 FINANCING COSTS

The Company's financing cost of service consists of:

- Cost of Debt;
- Cost of Equity; and
- Depreciation and Amortization.

FortisBC's financing costs for Cost of Debt and Cost of Equity for purposes of the 2012-13 RRA are based on a deemed capital structure of 60 percent debt and 40 percent equity, pursuant to Commission Order G-58-06.

The Company's Cost of Debt is determined by the percentage of debt included in the capital structure, and the interest rate on that debt. The total percentage of debt at 60 percent is determined by the Commission, however the allocation between long-term and short-term debt is managed by the Company. The interest rate on the debt is determined by the banks, capital markets and the Company's credit ratings. Under the Company's PBR Plan, all variances between approved and actual Cost of Debt are flowed back 100 percent to the customer. The Company's Cost of Equity is determined by the percentage of equity included in the capital structure, and the allowed ROE, both of which are ordered by the Commission. The Company's ROE was approved pursuant to Commission Order G-162-09

The table below provides an overview of the deemed capital structure and the weighted average cost of capital for 2010 through to 2013.

Table 4.7 Financing Costs

		Actual 2010	Approved 2010	Forecast 2011	Forecast 2012	Forecast 2013
				($000s)		
1	CAPITALIZATION					
2	Debt	548,917	655,945	642,718	687,152	727,309
3	Common Equity	396,927	437,296	428,479	458,101	484,872
4		945,844	1,093,241	1,071,197	1,145,253	1,212,181
5						
6	Equity as % of Total	42%	40%	40%	40%	40%
7						
8	EARNED RETURN					
9	Interest Expense	35,138	40,506	39,364	41,320	43,553
10	Net Earnings	38,293	43,292	45,922	45,352	48,002
11		73,431	83,798	85,286	86,672	91,555
12	RETURN ON CAPITAL					
13	Weighted Average Cost of Debt	6.40%	6.18%	6.12%	6.01%	5.99%
14	Return on Equity	9.65%	9.90%	10.72%	9.90%	9.90%
15	Weighted Average Cost of Capital	7.76%	7.67%	7.96%	7.57%	7.55%

4.7.1 Cost of Debt

Cost of Debt included in this RRA reflects the anticipated debt issuances and retirements over the forecast period, as well as the interest expense that has been calculated based on embedded interest rates for existing debt, and external forecasts of interest rates for new debt draws and issuances. Debt consists of both Long-term Debt and Short-term Debt.

The following table summarizes FortisBC's annual weighted debt balances and cost of debt for 2010 actual, 2011 Approved and the latest 2011 forecast.

1 **Table 4.7.1-1 Weighted Average Cost of Debt (2010-2011)**

Description of Debt	Maturity Dates	Rates	2010 Actual Weighted Average Balance ($000s)	2010 Actual Interest Expense ($000s)	2011 Approved Weighted Average Balance ($000s)	2011 Approved Interest Expense ($000s)	2011 Forecast Weighted Average Balance ($000s)	2011 Forecast Interest Expense ($000s)
Long-Term Debt								
Series F	16-Oct-12	9.65%	15,000	1,448	15,000	1,448	15,000	1,448
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200	25,000	2,200
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193	25,000	2,193
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953	25,000	1,953
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672	140,000	7,672
Series 1 - 05	09-Nov-35	5.60%	100,000	5,602	100,000	5,601	100,000	5,601
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195	105,000	6,195
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405	105,000	6,405
MTN Series 2 - 2010	24-Nov-50	5.00%	12,603	507	110,000	5,609	100,000	5,000
Series 2013	30 year est.	5.90%	-	-	-	-	-	-
Total Long-Term Debt			552,603	34,174	650,000	39,275	640,000	38,666
Weighted average rate on Long-Term Debt				6.18%		6.04%		6.04%
Short-Term Debt								
Draws on facility/deemed adjustment			(3,686)	(184)	5,945	220	2,718	(110)
Financing Fees								
Total Standby Fees				560		511		458
Total Banking Agreement Charges				410		260		150
Other financing fees				143		170		165
Demand Line interest				35		70		36
Total Financing Fees				1,148		1,011		809
Total Short-Term Debt			(3,686)	964	5,945	1,231	2,718	699
Weighted average rate on Short-Term Debt				-26.15%		20.71%		25.72%
Total Long-Term and Short-Term Debt			**548,917**	**35,138**	**655,945**	**40,506**	**642,718**	**39,365**
Weighted average rate on Total Debt				**6.40%**		**6.18%**		**6.12%**

2 Total Cost of Debt of $39.4 million in 2011 is forecast to be approximately $1.1 million lower
3 than the $40.5 million approved in rates. Under the terms of the PBR mechanism currently in
4 place through to the end of 2011, this variance is flowed-through as a reduction to 2012 rates as
5 described in Section 4.8.1.

6 The following table summarizes FortisBC's annual weighted debt balances and cost of debt
7 forecast for 2012 and 2013.

1

Table 4.7.1-2 Weighted Average Cost of Debt (2012-2013)

Description of Debt	Maturity Dates	Rates	2012 Forecast Weighted Average Balance ($000s)	2012 Forecast Interest Expense ($000s)	2013 Forecast Weighted Average Balance ($000s)	2013 Forecast Interest Expense ($000s)
Long-Term Debt						
Series F	16-Oct-12	9.65%	12,483	1,205	-	-
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672
Series 1 - 05	09-Nov-35	5.60%	100,000	5,600	100,000	5,600
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405
MTN Series 2 - 2010	24-Nov-50	5.00%	100,000	5,000	100,000	5,000
Series 2013	30 year est.	5.90%	-	-	25,151	1,484
Total Long-Term Debt			637,483	38,422	650,151	38,701
Weighted average rate on Long-Term Debt				6.03%		5.95%
Short-Term Debt						
Draws on facility/deemed adjustment			49,669	2,002	77,158	4,004
Financing Fees						
Total Standby Fees				367		301
Total Banking Agreement Charges				275		280
Other financing fees				180		190
Demand Line interest				74		77
Total Financing Fees				896		848
Total Short-Term Debt			49,669	2,898	77,158	4,852
Weighted average rate on Short-Term Debt				5.83%		6.29%
Total Long-Term and Short-Term Debt			**687,152**	**41,320**	**727,309**	**43,553**
Weighted average rate on Total Debt				**6.01%**		**5.99%**

2

4.7.1.1 LONG-TERM DEBT FINANCING

Approximately 90 percent of FortisBC's interest expense for 2012 and 2013 is driven by embedded long-term debt, depending on the timing of a long-term debt issuance. The Company is a public debt issuer and since 2004 has issued public long-term debt by way of prospectus.

In 2007, the weighted average interest rate on long-term debt interest was 6.50 percent and is forecast to be approximately 6.01 percent for 2012 and approximately 5.99 percent for 2013. During the term of the PBR Plan, customers have benefited from the decrease in the weighted average interest rates on embedded long-term debt as the entire savings have flowed back to customers. These cost of debt savings are driven largely by market conditions, but have also been somewhat influenced by the credit ratings upgrades obtained in 2010. The upgrades reflected the progress made by the Company in addressing issues previously identified as credit challenges, including increased liquidity obtained through the operating credit facilities. On May 6, 2010 Moody's Investors Service upgraded the rating to Baa1, Stable Outlook from Baa2, Stable Outlook. Additionally, on October 1, 2010, DBRS Limited upgraded the rating to A (low), Stable Trend from BBB (high), Stable Trend. The Moody's report is attached as Appendix H, and the DBRS Credit Opinion is attached as Appendix I..

Generally, when the Company's $150 million operating credit facilities and upcoming debt maturities reach approximately $100 million, the Company prepares to issue longer term public debt. Proceeds are then used to repay the credit facilities, provide for upcoming cash outflows and refinance maturing debt. The $100 million level provides the Company with some flexibility in the timing of issuing new bonds before reaching its approximate $150 million credit facility maximum. In addition, the public debt markets generally consider $100 million to be the minimum issue size that allows for a reasonable level of liquidity. In other words, it is the level that investors expect, and competition provides for reasonable pricing.

2010 Medium Term Note (MTN) Series 2 Senior Unsecured Debenture Issuance

On November 24, 2010, the Company issued senior unsecured MTN Debentures Series 2 in the amount of $100 million at a rate of 5.00 percent, to be paid semi-annually with a term of forty years. The MTN Debentures Series 2 issuance represented the lowest coupon of all the Company's embedded long-term debt and those savings have been embedded for the benefit of customers over the next forty years. The proceeds were used to pay down the operating credit facility that had been used to finance the Company's capital expenditure program and for working capital requirements. The $100 million of MTN Debentures Series 2 were issued pursuant to Commission Order G-51-09 which approved FortisBC's application to issue up to $300 million from time to time, according to the terms of a Shelf Prospectus, until June 11, 2011. The entire positive variance between actual and forecast interest expense related to the 2010 MTN Debentures Series 2 debt issuance has been flowed back to customers.

2012 Debt Maturity

FortisBC has $15.0 million in Secured Debentures due for redemption on October 16, 2012. The maturity is expected to be funded by draws on the Company's $150 million operating credit facility and funds from operations.

2013 Debt Issuance

The Company has forecast a long-term debt issuance in the last half of 2013 in the amount of $120.0 million with an expected term of 30 years and a coupon rate of 5.90 percent. Prior to issuance in 2013, the Company will request approval to issue this either under a short form prospectus, similar to 2005 and 2007 long-term debt issuances, or under a shelf prospectus program similar to the 2009 and 2010 MTN debentures. The forecast long-term debt issuance will maintain the Company's approved 60 percent debt capitalization structure and will primarily finance the Company's capital expenditure program and working capital requirements. The details regarding the long-term debt issuance cost can be found in Section 5.4.6 Deferred Debt Issue Costs.

Forecast of Long-term Interest Rates for 2013 Debt Issuance

The Company uses interest rate forecasts to estimate future interest expense, including the rate used for the proposed 2013 debt issuance with a term of 30 years. Forecasts of benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for new issues of long-term debt. The forecasts are averages of projections by four Canadian Chartered banks. Credit spreads on new long-term debt, using a term of 30 years, approximate current indicative rates specific to FortisBC.

Table 4.7.1.1 Long-Term Interest Rate Forecast

30-year Government of Canada Bond	4.45%
Long-term Debt Rate Spread	1.45%
All-in 30-year Borrowing Rate	5.90%

4.7.1.2 - SHORT-TERM DEBT FINANCING

FortisBC obtains short term funding primarily through the issuance of Bankers' Acceptances and prime rate margin loans drawn on its $150 million operating credit facility. On April 28, 2011, the Company renegotiated its operating credit facility pursuant to Order G-59-11 to provide greater flexibility and liquidity, while extending the term of the Company's operating credit facilities. The amended operating credit facility is comprised of a $100.0 million, three-year revolving facility maturing on May 7, 2014 and a $50.0 million, 364-day revolving facility maturing on May 3, 2012. The operating credit facilities provide the Company with short term liquidity to finance its ongoing capital program and working capital requirements. Generally the Company targets to replace the operating credit facilities when draws approach approximately $100 million in order to embed long-term debt to match the Company's long-term assets.

Forecast of Short-Term Debt Balances for 2012 and 2013

The weighted average short-term debt balance is representative of either the weighted average of draws on the operating credit facility or as a deemed debt adjustment. The deemed debt adjustments are notional entries that are required to account for the timing difference in financing rate base and to ensure that only 60 percent of rate base is financed with debt.

For 2010 the short-term debt balance was in a deemed debt adjustment position of $3.7 million. The short-term debt balance was in the position of operating credit facility draws in the amount of $5.9 million as part of the 2011 approved rates and $2.7 million for the 2011 updated forecast included in the 2012-13 RRA.

For the 2012 and 2013 forecast period, the short-term debt balance for regulatory purposes is forecast to be a weighted average of draws on the operating credit facility of $49.7 million and $77.2 million respectively. The short-term debt balances are expected to increase over 2012 and into 2013 until a forecast long-term debt is issued in the last half of 2013, the proceeds of which will be used to pay down the operating credit facility balance.

Forecast of Short-Term Interest Rates for 2012 and 2013

The Company uses forecasts of the Banker's Acceptance Rates and Prime Interest rate are used in determining the overall interest rates for short-term debt operating credit facility draws. The forecasts are averages of projections made by leading economists at four Canadian chartered banks.

Short-term interest rates are projected to increase in the coming months. Canadian chartered banks have forecast Bankers' Acceptances to remain on average at 1.37 percent for 2011 (using the Canadian 3 month Treasury bill rates), and then increase to an average of 3.90 percent for 2013. The Company then layers on the Acceptance Fee Rate of 1.25 percent, pursuant to the Company's April 28, 2011 renegotiated operating credit facility agreement and considering the Company's 2010 ratings upgrade, to arrive at a total Banker's Acceptance interest rate of 3.95 percent for 2012 and 5.15 percent for 2013.

Chartered banks expect the Prime Rate (Overnight Bank Rate plus 200 basis points) to remain on average at 3.63 percent for 2011 and increase to an average of 4.50 percent for 2012 and 5.25 percent for 2013. The Company then layers on the Prime Rate Margin of 0.25 percent, pursuant to the Company's April 28, 2011 renegotiated operating credit facility agreement and considering the Company's 2010 ratings upgrade, to arrive at a total average Prime Interest Rate of 4.75 percent for 2012 and 5.50 percent for 2013.

The following table outlines the short-term interest rate forecast for 2012 and 2013.

Table 4.7.1.2-1 Short-Term Interest Rate Forecast

Banker's Acceptance's	2012	2013
Banker's Acceptance Rates (3 month T-bill)	2.70%	3.90%
Acceptance Fee Rate	1.25%	1.25%
Bankers' Acceptance Rate	3.95%	5.15%
Prime Rate Loan		
Prime Rate (Overnight Bank Rate plus 200 bps)	4.50%	5.25%
Prime Rate Margin	0.25%	0.25%
Prime Interest Rate	4.75%	5.50%
Weighted Average Short-term Debt Rate	4.03%	5.19%

The calculation for short-term interest expense is determined by applying the short-term debt rates to the forecast average short-term debt balances for each loan type.

The following table summarizes the short-term interest expense forecast for 2012 and 2013.

Table 4.7.1.2-2 Short-Term Interest Expense Forecast

2012	Interest Rate	Average Principle ($000s)	Percentage of Principal of Financing	Interest ($000s)
Banker's Acceptance	3.95%	44,702	90.00%	1,766
Prime Rate Loan	4.75%	4,967	10.00%	236
Average all-in cost	4.03%	49,669		2,002
2013	**Interest Rate**	**Average Principle ($000s)**	**Percentage of Principal of Financing**	**Interest ($000s)**
Banker's Acceptance	5.15%	69,442	90.00%	3,577
Prime Rate Loan	5.50%	7,716	10.00%	426
Average all-in cost	5.19%	77,158		4,004

Forecast of Financing Fees for 2012 and 2013

The Company forecasts financing fees related to the cost of short-term and long-term debt based on historical costs and forecast levels of debt. Financing fees are included in the forecast total short-term debt interest expense and consist of standby fees, banking agreement charges, demand line interest and other fees. The relatively fixed Financing Fees can distort the Weighted Average Cost of Short Term Debt rate.

- **Standby fees** – are calculated on the difference between the average forecast draws on the credit facility and the total amount available, multiplied by the standby fee rate pursuant to the Company's April 28, 2011 renegotiated operating credit facility agreement. The forecast standby fee rate for 2012 and 2013 is 0.30 percent. This fee compensates the bank syndicate for providing continued access to the operating credit facility on short notice.
- **Banking agreement charges** – are fees associated with the annual renewal of the Company's operating credit facilities among a syndicate of Chartered Canadian banks, as well as an annual lender fee.
- **Demand line interest** – is calculated on any draws against the $10 million unsecured demand credit facility at the prime interest rate.
- **Other** – consists primarily of interest due to customers on outstanding security deposits and interest relating to the sublease of space in the Trail Office building.

Request for Interest Expense Variance Deferral Account

To avoid potential gains or losses on forecasting interest expense, for the 2012 and 2013 forecast period FortisBC is proposing to accumulate variances from forecast within an Interest Expense Variance deferral account. This proposed rate base deferral account would capture all variances relating to long and short-term interest expense, including financing fees, as the cost of debt can be largely influenced by capital market conditions which are less predictable and largely outside of the Company's control. During the last six years of FortisBC's PBR term, as approved under BCUC Order no. G-58-06, the difference between actual and forecast interest expense was captured in a deferral account and treated in a similar requested manner for rate-setting purposes. For purposes of the 2012 and 2013 revenue requirement, any additions to this rate base deferral account would be included in the deferred charges schedule and an amortization term of any accumulated variances will be proposed as part of the 2014 RRA.

Cost of Debt Conclusion

The total of all the above actual and forecast interest rates and financing fees results in a weighted average cost of debt of 6.40 percent for 2010 and approximately 6.12 percent for 2011. The Company is forecasting a weighted average cost of debt of approximately 6.0 percent for 2012 and 2013. These forecast weighted average costs of total debt for 2012 and 2013 are lower than in recent years. These forecast decreases in the cost of debt rates are driven largely by market conditions, but have also been somewhat influenced by the Company's efforts in addressing credit ratings challenges which resulted in credit ratings upgrades during 2010.

FortisBC maintains adequate credit facilities to provide sufficient liquidity to meet the ongoing working capital requirements and address any concerns that may result from tighter credit markets. In the last six years, the Company has become a more active participant in the debt capital markets and has fostered stronger relationships with its lenders, including the credit facility banking syndicate.

4.7.2 Cost of Equity

The Company's Cost of Equity is determined by the percentage of equity included in the deemed capital structure, approved pursuant to Commission Order G-58-06, and the allowed ROE, approved pursuant to Commission Order G-162-09.

Capital Structure

The Company has prepared its 2012 and 2013 RRA based on a deemed capital structure of 60 percent debt and 40 percent common equity. This deemed capital structure was approved pursuant to Commission Order G-58-06. FortisBC is proposing to keep the deemed capital structure of 40 percent equity and 60 percent debt unchanged for the 2012-13 RRA.

Pursuant to Commission Order G-11-11, the Company has forecast a $10 million Common Share Equity issuance in 2011 in order to maintain its deemed capital structure of 60 percent debt and 40 percent equity, subject to Commission approval in a later application. No common share equity issuances are expected in 2012 and 2013.

Allowed Return on Equity

<u>Background</u>

For many years, the Commission annually set the allowed ROE for utilities in British Columbia, including FortisBC, based on the Benchmark ROE for FEI using a formula that ties the BC utilities' rates of return on equity to the forecast yield on long-term (30 year) Canada bonds for the forthcoming year. This formula has been commonly referred to as the Automatic Adjustment Mechanism (AAM). In revenue requirement applications prior to 2010, FortisBC's Allowed ROE had been set using the most recent Consensus Economics forecast at the time of the revenue requirement application, in accordance with the BCUC's AAM. FEI had been the benchmark utility for purposes of applying FortisBC's risk premium of 40 basis points which was confirmed by Commission Order G-58-06.

<u>FortisBC Energy Utilities (previously known as Terasen Utilities) ROE Decision</u>

In May 2009 the FortisBC Energy Utilities applied to the BCUC for, among other things, a review of the current ROE mechanism applicable to regulated utilities in British Columbia.

The BCUC issued the FortisBC Energy Utilities ROE Decision dated December 16, 2009, setting the ROEs for the FortisBC Energy Utilities and confirming that FEI will continue to serve as a benchmark for calculating the ROE allowed in rates for certain utilities regulated by the BCUC, including FortisBC.

The ROE for FortisBC in 2010 was established at 9.90 percent, using FEI's approved 9.50 percent ROE and FortisBC's 40 basis points risk premium pursuant to Commission Order G-58-06. At the time of the decision, the Commission also determined that the AAM that was used to determine the ROE on an annual basis will no longer apply, and the ROE as determined in the decision will apply until changed by the BCUC.

2012 and 2013 Revenue Requirements ROE

FortisBC's ROE remained at 9.90 percent for the 2011 RRA pursuant to Commission Order G-162-09. For purposes of the 2012-13 RRA, FortisBC has continued to use an ROE of 9.90 percent, calculated as FEI's approved 9.50 percent ROE pursuant to the FortisBC Energy Utilities ROE Decision and layering on FortisBC's 40 basis points risk premium pursuant to Commission Order G-58-06.

4.7.3 Depreciation and Amortization

Table 4.7.3 Depreciation and Amortization

	Actual	Forecast		
	2010	2011	2012	2013
Amortization of Deferred Charges	3,695	3,233	4,468	4,358
Depreciation	38,075	42,118	46,931	48,870
Total Depreciation and Amortization	41,770	45,351	51,399	53,228

Depreciation

The Company forecasts that depreciation will increase from $38.1 million in 2010 to $46.9 million in 2012 and $48.9 million in 2013. The increase in forecast depreciation is due to increases in plant in service resulting from the Company's capital expenditure program.

For the period 2006 to 2011, depreciation was based on a composite rate of 3.2 percent as approved by Order G-58-06. FortisBC has prepared its 2012-13 RRA based on the results of an updated Depreciation Study (2011 Depreciation Study) which has been prepared using the Average Service Life (ASL) procedure, which is consistent with the procedure used in the Depreciation Study filed with the 2006 RRA (2006 Depreciation Study) and is considered acceptable under both pre-changeover CGAAP and US GAAP. The Company is requesting approval to apply these rates for depreciation purposes starting in 2012. The Company is also requesting approval to continue its accounting treatment of costs of removal. The Company has not proposed incorporating a provision for negative salvage in rates for 2012 and 2013 because it would result in a significant increase to customer rates. Although FortisBC does support the principle of recognizing a provision for negative salvage in rates so that customers who are receiving the benefit of the asset also pay for the cost of salvage, the Company has not proposed incorporating a provision for negative salvage in rates for 2012 and 2013 because it would result in a significant increase to customer rates.

Amortization of Deferred Charges

Amortization of deferred charges is addressed in Section 5.4 as each separate deferral is subject to a different amortization period pursuant to the related BCUC approval order. The Company expects an increase in amortization of deferred charges in 2012 and 2013 compared to 2010 and 2011, primarily as a result of the disposition in 2012 and 2013 of increased regulatory deferrals recorded in 2010 and 2011.

4.7.3.1 DEPRECIATION STUDY AND RATES

Pursuant to Order G-184-10 approving the 2011 NSA, FortisBC is filing its 2011 Depreciation Study, which is attached as Appendix J.

The practice of regularly reviewing and updating depreciation lives ensures that the depreciation rates reflect the state of the current asset base. Reviewing depreciation rates on a regular basis is also a requirement of pre-changeover CGAAP, US GAAP and IFRS.

A new study was commissioned and completed by Gannett Fleming Inc., Valuation and Rate Division for inclusion in this 2012-2013 RRA. Gannett Fleming is a leading depreciation, valuation and ratemaking consulting firm in North America.

The 2011 Depreciation Study is based on the December 31, 2009 plant in service values, recommends a composite depreciation rate of 3.2 percent related to the life of the depreciable assets and does not include a provision for negative salvage. The 3.2 percent composite depreciation rate is what has been utilized in the calculation of the 2012-13 RRA, which is in line with the approved composite depreciation rate of 3.2 percent pursuant to Order G-58-06 which has been applied effective 2006 through to 2011. FortisBC considers the results of this most recent study as being reasonable and representative of the service life profiles of the Company's depreciable assets, and proposes to adopt the recommended depreciation rates outlined in the 2011 Depreciation Study effective January 1, 2012 to appropriately allocate the consumption of the asset's useful lives over time.

4.7.3.2 BACKGROUND

FortisBC filed a formal Depreciation Study in 1983 (1983 Depreciation Study) based on plant in service as at December 31, 1982. These rates remained unchanged until a discussion paper on the service life of transmission and distribution assets was completed by the Company in 1999 (1999 Discussion Paper). The 2000-2002 NSA, as approved in Order G-134-99, incorporated certain changes to depreciation recommended in the discussion paper, including an increase in the estimated useful lives of transmission and distribution assets from approximately 35 years to 50 years and a further offset to depreciation expense in the form of a Rate Stabilization Adjustment (RSA). The change in service lives of transmission and distribution assets resulted in an approximate $3.4 million decrease to annual depreciation expense beginning in 2000. The RSA was a notional reversal of accumulated depreciation to reflect the historical accumulation of the deemed over-depreciation of transmission and distribution assets. The purpose of the RSA was to limit annual electricity rate increases to no more than 5 percent during the period covered by the 2000-2002 NSA. It was utilized only once, in 2001, with a $3.1 million decrease to depreciation expense and corresponding decrease to accumulated depreciation. None of these changes to depreciation were based on expert opinion.

4.7.3.3 2005 REVENUE REQUIREMENTS APPLICATION

Depreciation rates approved in previous rate applications, which incorporate the 1983 Depreciation Study and the amendments approved in the 1999 Discussion Paper, were proposed for use in FortisBC's 2005 RRA. However, during the 2005 RRA process it was indicated that depreciation rates should be based on the economic life of the assets and not fixed for other purposes, as had been done in the 2000-2002 NSA. Evidence of depreciation rates potentially being artificially low were provided by external analysis in the November 18, 2004 DBRS Credit Rating Report, which expressed that the Company's current composite depreciation rate appeared low in comparison to other utilities (*2005 RRA, BCUC IR 13.0*). Similarly, the November 16, 2004 Moody's Credit Rating Report cited one of the Company's credit challenges being the relatively low depreciation rate for rate-making purposes (*2005 RRA, BCUC IR 15.0*).

The 2005 RRA Decision, as approved in Order G-52-05, accepted the proposed depreciation rates and directed FortisBC to file a formal Depreciation Study as part of its next revenue requirements application.

4.7.3.4 2006 REVENUE REQUIREMENTS APPLICATION

FortisBC filed the 2006 Study, prepared by Gannett Fleming, with the 2006 RRA based on plant in service at December 31, 2004. The study proposed a composite depreciation rate of 3.6 percent. Pursuant to Order G-58-06, the following was determined:

- The proposed depreciation rates for six asset classes (Transmission Stations, Transmission Poles Towers & Fixtures, Transmission Conductors & Devices, Distribution Poles Towers & Fixtures, Distribution Conductors & Devices, and Structures-Masonry) were adjusted downwards to 3.0 percent in order to reflect longer average service lives for those assets, which resulted in reducing the composite depreciation rate to 3.2 percent;
- The RSA was approved to be amortized over a ten year period, beginning in 2006;
- The parties held differing views on negative salvage values, and analysis of the issue was agreed to be deferred for the term of the PBR agreement;
- The current practice of depreciating assets based on plant in service at the beginning of the year will continue; and
- The parties did not agree that the findings of the Depreciation Study were otherwise appropriate and no precedent value was attached to the Depreciation Study.

The results of the 2006 NSA did not arrive at a principled decision on the appropriateness of the recommendations in the Depreciation Study proposed by the Company. Rather, depreciation rates were agreed to on a negotiated basis between the Company and the NSA participants.

No precedent value was established by the settlement and it was agreed that depreciation would be reviewed at the conclusion of the PBR term.

4.7.3.5 2011 DEPRECIATION STUDY OVERVIEW

For the purposes of the 2012-13 RRA, FortisBC retained Gannett Fleming to conduct a formal Depreciation Study of its utility rate base assets. The study, which is included in Appendix J, has been prepared based on plant in service as of December 31, 2009. FortisBC considers that the study results continue to be applicable for the 2012 and 2013 forecast period as Gannett Fleming estimates the rates calculated in the depreciation study are reasonable for a period of three to five years. FortisBC has internally updated the plant balances in the 2011 Depreciation Study and recalculated the revenue requirement impacts of implementing the study.

Overall, the composite depreciation rate was determined to be 3.2 percent, which is in line with the current composite depreciation rate approved by Order G-58-06. As a result of the significant investment in new utility rate base assets since the 2006 Study, the composite remaining life for a number of asset classes has been extended, thus putting downward pressure on the depreciation rate. However, there are several factors which apply upward pressure:

- As explained above in Section 4.7.3.3 and 4.7.3.4, plant in service has been under-depreciated due to rates not being revised from 1982 to 1999;
- The increase in the estimated useful lives of transmission and distribution assets from approximately 35 years to 50 years for 2000 to 2005; and
- The depreciation rates for six asset classes being adjusted downwards for 2006 to 2011.

This accumulated depreciation deficiency that exists in most transmission and distribution accounts is incorporated into the depreciation rates proposed in the 2011 Depreciation Study. In addition, costs of removal incurred in prior years have been included in the accumulated depreciation of certain asset classes in the study, which results in a higher net book value and therefore a larger amount to be depreciated in the future. Lastly, as explained below, the Vehicles asset class had its estimated useful life reassessed to account for actual data analyzed from 2005 to 2009.

The 2011 Depreciation Study includes separate schedules outlining the recommended accrual rates for the recovery of the original cost of investment (see Schedule 1 of Appendix J) and recovery of the estimated cost removal (see Schedule 2 of Appendix J). This second component, recovery of the estimated cost of removal, is also referred to as the provision for negative salvage in depreciation rates.

4.7.3.6 2011 DEPRECIATION STUDY HIGHLIGHTS

Gannett Fleming has estimated the depreciation rates using various statistical methods and informed judgment based on its extensive experience in the electricity industry and its involvement in the 2006 Study. In addition, a general understanding of the characteristics of the plant in service and information with respect to the reason for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel of the Company.

Straight-line depreciation was developed for the assets in a particular class beginning with the original cost, the estimated average and remaining service life characteristics and then accounting for the accumulated depreciation already booked in that class. Gannett Fleming has estimated the depreciation accrual rates using the ASL procedure for most asset classes, which is consistent with the procedure used in the 2006 Study. In the ASL procedure, the rate of annual depreciation is based on the average life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life. The calculation was based on the attained ages and estimated service life characteristics for each depreciable group of assets applicable to the original cost of plant at December 31, 2009. For certain asset classes in general plant, an amortization accounting method was proposed, which is a simplified group method that determines an amortization period and allocates the remaining book values for the remaining vintage years. This method was used for the Office Furniture and Equipment, Computer Equipment and Software, PC Computer Equipment and Software, Tools and Work Equipment, and Communication Structures and Equipment asset classes.

The Vehicles asset class was previously approved to be depreciated at a nominal rate, with the expectation that proceeds from disposal would almost fully offset the depreciated cost of each vehicle. Based on data analyzed from 2005 to 2009, proceeds from disposal of vehicles were less than expected and there are also certain transportation equipment such as trailers and lift trucks that have little to no end of life value. For these reasons, the depreciation rate for vehicles was updated to reflect actual results for the period studied as well as industry standards.

The composite depreciation rate recommended in the 2011 Depreciation Study related to the original cost of investment is 3.2 percent (see Schedule 1 of Appendix J), which is in line with the current composite depreciation rate approved by Order G-58-06. Implementation of the recommended rate, which is set out in Table 4.7.3.6 below, would decrease the depreciation expense in 2012 by approximately $0.2 million as compared to those rates approved by Order G-58-06.

Table 4.7.3.6 Effect on 2012 Depreciation Expense Using Rates from 2011 Depreciation Study

Line	Account	Dscription	Forecast Asset Balance at Dec 31, 2011	Current Rate	Recommended Depreciation Rate	Depreciation Based on Current Rate	Depreciation Based on Recommended Rate	Increase / (Decrease)
		Hydraulic Production Plant						
1	330	Land Rights	962	2.6%	3.8%	25	37	12
2	331	Structures and Improvements	12,791	1.2%	1.3%	159	165	6
3	332	Reservoirs, Dams & Waterways	27,265	1.7%	2.0%	464	548	84
4	333	Water Wheels, Turbines and Gen.	83,130	2.2%	2.0%	1,829	1,621	(208)
5	334	Accessory Equipment	38,123	2.4%	2.4%	911	900	(11)
6	335	Other Power Plant Equipment	60,354	2.3%	2.3%	1,398	1,400	2
7	336	Roads, Railroads and Bridges	1,287	1.4%	1.5%	18	19	1
8			223,912	2.1%	2.1%	4,804	4,690	(114)
9		**Transmission Plant**						
10	350	Land Rights	7,447	0.0%	0.0%	-	-	-
11	350.1	Land Rights - Clearing	6,412	1.6%	1.5%	103	94	(9)
12	353	Station Equipment	218,789	3.0%	3.4%	6,564	7,526	962
13	355	Poles Towers & Fixtures	87,371	3.0%	2.6%	2,621	2,307	(314)
14	356	Conductors and Devices	74,135	3.0%	2.1%	2,224	1,520	(704)
15	359	Roads and Trails	1,121	2.9%	2.7%	33	30	(3)
16			395,276	2.9%	2.9%	11,545	11,477	(68)
17		**Distribution Plant**						
18	360	Land Rights	3,605	0.0%	0.0%	-	-	-
19	360.1	Land Rights - Clearing	10,879	2.1%	2.7%	228	289	61
20	362	Station Equipment	199,197	3.0%	2.2%	5,976	4,402	(1,574)
21	364	Poles Towers & Fixtures	145,829	3.0%	2.1%	4,375	3,106	(1,269)
22	365	Conductors and Devices	232,319	3.0%	2.6%	6,970	5,971	(999)
23	368	Line Transformers	105,958	2.9%	3.4%	3,073	3,613	540
24	369	Services	10,786	0.0%	0.2%	-	17	17
25	370	Meters	14,299	3.5%	6.7%	497	955	458
26	371	Installation on Customers' Premises	938	0.0%	0.0%	-	-	-
27	373	Street Lighting and Signal System	11,438	2.4%	23.0%	275	2,628	2,353
28			735,247	2.9%	2.9%	21,394	20,981	(413)
29		**General Plant**						
30	389	Land	12,093	0.0%	0.0%	-	-	-
31	390	Structures-Frame & Iron	337	0.8%	0.7%	3	2	(1)
32	390.1	Structures-Masonry	25,510	3.0%	6.1%	763	1,559	796
33	391	Office Furniture & Equipment	5,912	7.5%	3.6%	443	215	(228)
34	391.1	Computer Equipment	69,737	10.6%	7.6%	7,415	5,307	(2,108)
35	392	Transportation Equipment	20,554	0.4%	10.7%	82	2,201	2,119
36	394	Tools and Work Equipment	12,920	9.5%	4.0%	1,227	521	(706)
37	397	Communication Structures and Equipment	26,780	6.0%	8.1%	1,607	2,156	549
38			173,842	6.6%	6.9%	11,540	11,961	421
39								
40			1,528,276	3.2%	3.2%	49,283	49,109	(174)

4.7.3.7 NEGATIVE NET SALVAGE

The Company has not proposed incorporating a provision for negative salvage in rates for 2012 and 2013 because it would result in a significant increase to customer rates, although FortisBC does support the principle of doing so when the impact of doing so is not significantly detrimental to customer rate increases. Despite FortisBC not requesting a provision for negative salvage as part of the 2012-13 RRA, the following describes the principles, methodology and results of the depreciation study for negative salvage value.

Net salvage value is the proceeds received for property retired less any expenses incurred in connection with the sale or removal of the asset. When the removal costs are greater than the proceeds, it is referred to as negative net salvage value. In addition to the accrual rate related to the life of the assets, the Depreciation Study includes estimate provision for negative net salvage.

The estimates of net salvage were based in part on historical data, and in part through the professional judgment of Gannett Fleming, which has significant experience in the development of net salvage percentage estimates. In developing these estimates, Gannett Fleming included the following steps:

1. Annual retirement, gross salvage and cost of removal transactions for the period January 1, 1995 through December 31, 2009 were extracted from the plant accounting system.
2. A net salvage amount (gross salvage proceeds less cost of removal) was calculated for each historic year.
3. The net salvage amount determined above was compared to the original booked costs retired for each period in the manner described, which resulted in a net salvage percentage of original costs retired for each year.
4. The annual net salvage percentages were analyzed to determine a reasonable estimated net salvage percentage, resulting in a net salvage percentage based purely upon statistical analysis.
5. Each account was then analyzed based on the statistical analyses, the information provided by the operations groups regarding the current projects, and with the professional judgment of Gannett Fleming. Based on this analysis, a net salvage percentage for each account was determined.

The composite rate recommended in the Depreciation Study related to the provision for negative net salvage is 0.8 percent (see Schedule 2 of Appendix J). Implementation of the recommended rate, which is set out in Table 4.7.3.7 below, would increase the annual depreciation expense by approximately $12.8 million.

Table 4.7.3.7 Effect on 2012 Depreciation Expense Using Salvage Rates from 2011 Depreciation Study

Line	Account	Dscription	Forecast Asset Balance at Dec 31, 2011	Current Rate	Recommended Depreciation Rate	Depreciation Based on Current Rate	Depreciation Based on Recommended Rate	Increase / (Decrease)
		Hydraulic Production Plant						
1	330	Land Rights	962	0.0%	0.0%	-	-	-
2	331	Structures and Improvements	12,791	0.0%	0.3%	-	41	41
3	332	Reservoirs, Dams & Waterways	27,265	0.0%	0.4%	-	95	95
4	333	Water Wheels, Turbines and Gen.	83,130	0.0%	1.1%	-	873	873
5	334	Accessory Equipment	38,123	0.0%	1.0%	-	377	377
6	335	Other Power Plant Equipment	60,354	0.0%	0.1%	-	84	84
7	336	Roads, Railroads and Bridges	1,287	0.0%	0.0%	-	-	-
8			223,912	0.0%	0.7%	-	1,471	1,471
9		**Transmission Plant**						
10	350	Land Rights	7,447	0.0%	0.0%	-	-	-
11	350.1	Land Rights - Clearing	6,412	0.0%	0.0%	-	-	-
12	353	Station Equipment	218,789	0.0%	1.3%	-	2,888	2,888
13	355	Poles Towers & Fixtures	87,371	0.0%	1.7%	-	1,520	1,520
14	356	Conductors and Devices	74,135	0.0%	1.3%	-	956	956
15	359	Roads and Trails	1,121	0.0%	0.0%	-	-	-
16			395,276	0.0%	1.4%	-	5,365	5,365
17		**Distribution Plant**						
18	360	Land Rights	3,605	0.0%	0.0%	-	-	-
19	360.1	Land Rights - Clearing	10,879	0.0%	0.0%	-	-	-
20	362	Station Equipment	199,197	0.0%	0.5%	-	1,076	1,076
21	364	Poles Towers & Fixtures	145,829	0.0%	1.2%	-	1,706	1,706
22	365	Conductors and Devices	232,319	0.0%	0.8%	-	1,951	1,951
23	368	Line Transformers	105,958	0.0%	1.0%	-	1,081	1,081
24	369	Services	10,786	0.0%	0.0%	-	-	-
25	370	Meters	14,299	0.0%	0.0%	-	-	-
26	371	Installation on Customers' Premises	938	0.0%	0.0%	-	-	-
27	373	Street Lighting and Signal System	11,438	0.0%	1.4%	-	154	154
28			735,247	0.0%	0.8%	-	5,969	5,969
29		**General Plant**						
30	389	Land	12,093	0.0%	0.0%	-	-	-
31	390	Structures-Frame & Iron	337	0.0%	0.0%	-	-	-
32	390.1	Structures-Masonry	25,510	0.0%	0.0%	-	-	-
33	391	Office Furniture & Equipment	5,912	0.0%	0.0%	-	-	-
34	391.1	Computer Equipment	69,737	0.0%	0.0%	-	-	-
35	392	Transportation Equipment	20,554	0.0%	0.0%	-	-	-
36	394	Tools and Work Equipment	12,920	0.0%	0.0%	-	-	-
37	397	Communication Structures and Equipment	26,780	0.0%	0.0%	-	-	-
38			173,842	0.0%	0.0%	-	-	-
39								
40			1,528,276	0.0%	0.8%	-	12,804	12,804

FortisBC currently does not provide for negative net salvage, but the Company does believe that estimates of negative salvage (removal costs less salvage proceeds) should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. This treatment recognizes that negative salvage is a cost of providing service and should be recovered from customers over the useful life of the asset. The inclusion of a provision for negative salvage value in depreciation rates is consistent with the BCUC Uniform System of

Accounts and is generally followed by other utilities across Canada. The BCUC Uniform System of Accounts states:

> *"There shall be charged monthly to account No. 303, "Depreciation", or other appropriate accounts with concurrent credits to the accounts for accumulated depreciation amounts which will allocate the service value for the plant over its estimated service life in a systematic and rational manner. The service value of the assets, for depreciation purposes, shall be their cost less their estimated net salvage value. Net salvage value means the salvage value less removal costs. The charges for depreciation shall be computed in conformity with the group system under the straight line method at rates approved by the Commission."*

In a scenario that requests a provision of negative salvage in depreciation rates, it would be recommended following the traditional approach for electric plant in service that require significant removal costs, with the provisions segregated by asset classes in a separate liability account. This treatment provides the best balance in achieving regulatory goals in that it distributes costs to ratepayers equitably over time, improves utility accountability for removal costs collected from ratepayers through tracking provisions separately by asset class, while achieving an appropriate balance with respect to administrative costs relating to implementation, maintenance and tracking.

Despite the Company's acknowledgement that including a provision for negative salvage is the most appropriate method of collecting removal costs, implementing the recommended salvage accrual rate would result in a significant increase to customer rates. As a result, in order to manage rate increases for the term of this application, FortisBC is not proposing to incorporate the recommended salvage accrual rates at this time and is proposing to reconsider for inclusion in a subsequent revenue requirements application. The Company's treatment and accounting for costs of removal is assessed below.

4.7.3.8 COSTS OF REMOVAL

Through to 2011, actual costs of removal, net of salvage proceeds, have been recorded against accumulated depreciation when incurred. Each time a depreciation study has been conducted, the future depreciation rates have been adjusted in the amount of the deferred costs of removal so that any costs of removal that are charged to accumulated depreciation will be reflected in future depreciation expense when it is refunded or collected in rates.

While FortisBC supports the principle of including a provision for negative salvage, the rate impact of including the full 0.8 percent negative salvage accrual rate in the 2012-13 RRA is currently prohibitive for FortisBC's customers. In light of the adverse impacts to customer rates, potential options to address this issue include:

- Applying the pre-collection of negative salvage to selected asset classes,
- Phasing negative salvage rates in over several years, or
- Continue with the current treatment of recognizing actual costs of removal in rate base against accumulated depreciation and begin amortizing these amounts into rates when a new Depreciation Study is performed every few years, similar to what has historically been done.

FortisBC recommends the third option of continuing to recognize costs of removal against accumulated depreciation and amortizing these costs into rates when an updated Depreciation Study is performed. This is the methodology that has been reflected in the 2012-13 RRA and no provision for negative salvage has been included in the depreciation rates.

4.7.3.9 GAINS AND LOSSES ON RETIREMENT

When an asset is retired, its Net Book Value is charged to accumulated depreciation, with no gain or loss reflected in income unless the disposal is outside the normal course of business or involves a major item of plant. Subsequent depreciation studies adjust future depreciation rates in the amount of the deferred gains or losses so that any gain or loss which is charged to accumulated depreciation will be reflected in future depreciation expense when it is refunded or collected in rates.

As part of the ASL method, gains and losses recognized on the retirement of assets are capitalized to accumulated depreciation instead of recognized in earnings. The reasoning behind this approach is that ASL is meant to provide an estimate of the rate to use to depreciate a pool of assets. If certain assets are retired prior or subsequent to the expected life estimate, then the accumulated depreciation account is adjusted to the extent that retired assets are under or over-depreciated. These “experience adjustments”, which represent a difference between actual life and expected life, are considered in future depreciation studies conducted using the same ASL method.

4.7.3.10 CHARGES LESS RECOVERIES

Included in Table 1 – C of Tab 7 are charges less recoveries, which are representative of the effects on accumulated depreciation from items retired from Property, Plant and Equipment. When an item is retired from service, its gross cost is removed from plant in service, as indicated in Table 1 – A of Tab 7. The related accumulated depreciation, less costs of removal and any gain or loss on retirement, are recorded against accumulated depreciation and included in Table 1 – C of Tab 7 as charges less recoveries.

4.7.3.11 AMORTIZATION OF CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Amortization of CIAC is calculated on the deferred balance at the start of the year and recognized as a reduction to depreciation expense over the life of the related assets, which is currently approved at 3.0 percent through to 2011. The Company receives customer contributions primarily for distribution line extensions containing poles and conductors. Therefore, similar to the currently approved rate of 3.0 percent, for the purposes of the 2012-13 RRA the Company is proposing to use the composite rate for the recovery of the original cost of investment for distribution poles (2.1 percent) and distribution conductors (2.6 percent) as outlined in the 2011 Depreciation Study (see Schedule 1 of Appendix J). This composite rate is approximately 2.4 percent.

4.7.3.12 PLANT NOT STUDIED

The 2011 Depreciation Study does not include an assessment of certain items that are included in plant in service and form part of depreciation expense on Table 1 – C of Tab 7. These items are explained as follows.

The Utility Plant Acquisition Adjustment is being depreciated in accordance with Order G-37-84, which directed the Company to apply an "amortization rate…consistent with the weighted rate of depreciation for similar plant items" which at the time was 1.6 percent. This regulatory determined rate was not contemplated in the 2011 Depreciation Study and therefore the Company proposes to maintain the previously approved depreciation rate pursuant to Commission Order G-37-84.

Leasehold Improvements are amortized on a straight-line basis over the term of each specific lease and are therefore not contemplated in the 2011 Depreciation Study.

In accordance with Order G-58-06, the Rate Stabilization Adjustment was determined to be amortized over a ten year period beginning in 2006. This regulatory determined rate was not contemplated in the 2011 Depreciation Study and therefore the Company proposes to maintain the previously approved depreciation rate pursuant to Commission Order G-58-06.

Land and land rights are not depreciable items of PP&E and are therefore not contemplated in the 2011 Depreciation Study.

4.8 INCENTIVES

Under the terms of the PBR NSA, Flow-through Adjustments in certain approved revenues and costs as compared to the forecast will be recovered from or refunded to customers. In addition, the variances in the actual earnings as compared to the Company's approved earnings (after being adjusted for certain revenue and cost variances) are shared with customers. Earnings Sharing Incentives, positive or negative, up to a 2 percent collar around the approved ROE will be shared equally between customers and FortisBC.

4.8.1 Flow-through Adjustments

Flow-through adjustments (including a 2010 incentive true-up) are forecast to reduce 2012 Revenue Requirements by approximately $2.4 million. The flow-through adjustments are shown in Table 4.8.1 below:

a) A flow-through decrease to 2012 of approximately $0.38 million to recognize a true-up from the forecast to actual 2010 incentive;

b) A flow-through decrease to 2012 of approximately $0.839 million to reflect lower Interest Expense than approved in 2011 rates;

c) A flow-through decrease to 2012 of approximately $0.059 million as a result of a Transmission Pole Rental contract (2011 revenue);

d) A flow-through decrease to 2012 of approximately $0.175 million as a result of a new Fiber Optic lease contract (2011 revenue);

e) A flow-through decrease to 2012 of approximately $0.223 million for a Water Fees rate reduction. Water fees were previously based on BC Hydro rates and are now based on the BC CPI; and

f) A flow-through decrease to 2012 of approximately $1.11 million. This reflects a change in rate class for Celgar as ordered by the Commission pursuant to order G-184-10 which states:

"and true-up to actual revenues received from Celgar in 2011 at the 2011 Annual Review. The true-up will flow through 2012 FBC rates."

The change is currently being disputed by Celgar. At this time the revenue has not been collected by FortisBC. Any change as a result of a later decision by the Commission or any uncollectable amounts from Celgar will flow-through to customers.

Table 4.8.1 True Up and Flow-through Adjustments

		Approved	Forecast	Variance	Income Tax Shield	Customer Share	Flow Through Adjustment
				($000s)			
1	2010 Incentive True Up	1,681	2,061	(380)	-	100%	**(380)**
2	Interest Expense	40,505	39,364	(1,142)	303	100%	(839)
3	Transmission Pole Rental Revenue	-	-	(80)	21	100%	(59)
4	Fibre Leasing Revenue	-	-	(237)	63	100%	(175)
5	Water Fees Rate Reduction	-	-	(303)	80.4	100%	(223)
6	Celgar Tariff Difference	-	-	(1,510)	400	100%	(1,110)
7	Flow Through Adjustment						**(2,406)**

4.8.2 ROE Sharing Mechanism Adjustment

Pursuant to the Commission order G-58-06 dated May 23, 2006 which states:

"In place of the previous multiple-component mechanism, the Parties agreed to a sharing based on actual financial performance compared to the Company's allowed ROE. All variances, positive or negative, equal to or less than 2.0%, will be shared equally between customers and the company. If the variance exceeds 2.0%, the excess will be placed in a deferral account for review at the next Annual Review."

The 2011 approved figures are according to Commission Order G-184-10. The ROE Sharing Mechanism Adjustment is forecast to reduce 2012 Revenue Requirements by approximately $2.6 million. The calculation of the incentive is shown in Table 4.8.2 below.

Any variance between the forecast adjustment and the actual as at December 31, 2011 will be retained in Deferred Charges and flowed through to rates in 2014.

Table 4.8.2: ROE Sharing Mechanism Adjustments

	2011 Approved	2011 Forecast	Variance	Customer Share	ROE Incentive Adjustment
($000s)					
Net Income for ROE sharing	43,292	48,553	(5,261)	50%	(2,630)
Common Equity	437,296	428,479			
Allowed ROE	9.90%	11.33%	1.43%	50%	0.72%

2012 – 2013 Revenue Requirements
(2012-13 RRA)

Tab 5
Rate Base

June 30, 2011

FortisBC Inc.

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5.0 INTRODUCTION

This section summarizes the forecast Utility Mid Year Rate Base (Rate Base) for the years 2011 through 2013 while comparing it with the actual Rate Base for 2010. A regulated utility's Rate Base represents the net investment in assets necessary to provide service to its customers. The utility finances its Rate Base through a combination of debt and equity, which is often referred to as invested capital. The total of interest and return on equity required to finance the utility's investment in Rate Base is known as Earned Return and forms a major component of the revenue requirement.

This section reviews the primary components of Rate Base for the Company, principally, Plant in Service, Construction Work in Progress (CWIP) not subject to Allowance for Funds Used During Construction (AFUDC), Plant Acquisition Adjustment, Deferred and Preliminary Charges, Accumulated Depreciation and Amortization, Contributions in Aid of Construction (CIAC), Allowance for Working Capital and Adjustment for Capital Additions.

Also included in this tab is a summary of the Company's 2011-2013 year end Plant in Service forecast, which is provided in further detail in Tab 7 of this Application.

5.1 UTILITY RATE BASE

Utility Rate Base is comprised mostly of the Company's investment in Property, Plant and Equipment necessary to provide service to its customers (Plant in Service). This investment is net of Retirements, Accumulated Depreciation and Amortization and CIAC, and includes CWIP not subject to AFUDC. Also included in Rate Base are certain other expenditures approved by the Commission, primarily comprised of the Plant Acquisition Adjustment related to generation plants, deferred Demand Side Management (DSM) expenses and other deferred expenditures. Finally, an Allowance for Working Capital and an Adjustment for Capital Additions are also added to, or deducted from Rate Base to correctly reflect the actual invested capital required to finance the Rate Base.

5.1.1 Utility Rate Base Summary

Table 5.1.1 below sets out the forecast Rate Base for 2011 through 2013 for purposes of determining rates and revenue requirements for 2012 and 2013. It also provides 2010 actual Rate Base for the purpose of comparison.

Table 5.1.1 Actual and Forecast Utility Rate Base Summary

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Plant in Service, January 1	1,273,476	1,403,617	1,533,337	1,619,327
2	Net Additions	130,141	129,720	85,990	125,932
3	Plant in Service, December 31	1,403,617	1,533,337	1,619,327	1,745,259
4					
5	Add:				
6	CWIP not subject to AFUDC	7,213	6,237	5,875	5,875
7	Plant Acquisition Adjustment	11,912	11,912	11,912	11,912
8	Deferred and Preliminary Charges	16,698	19,408	25,731	29,899
9					
10		1,439,440	1,570,893	1,662,845	1,792,946
11	Less:				
12	Accumulated Depreciation				
13	and Amortization	323,203	352,464	385,146	421,382
14	Contributions in Aid of Construction	93,763	97,049	104,641	111,698
15		416,967	449,513	489,787	533,080
16					
17	Depreciated Rate Base	1,022,473	1,121,380	1,173,058	1,259,865
18					
19	Prior Year Depreciated Utility Rate Base	915,158	1,022,473	1,121,380	1,173,058
20					
21	Mean Depreciated Utility Rate Base	968,815	1,071,926	1,147,219	1,216,462
22	Add:				
23	Allowance for Working Capital	5,756	7,361	1,654	1,007
24	Adjustment for Capital Additions	(28,934)	(8,090)	(3,620)	(5,288)
25					
26	**Mid-Year Utility Rate Base**	**945,637**	**1,071,197**	**1,145,253**	**1,212,181**

FortisBC's Rate Base is forecast to grow at an average level of approximately nine percent during 2011 through 2013, as indicated in Table 5.1.1 above. This growth is primarily attributable to capital additions for new plants, both growth and sustainment, necessary to support customer growth and ensure safe and reliable supply of electricity to the Company's ratepayers.

5.2 PLANT IN SERVICE

The largest component of Rate Base is Plant in Service. The Company's Plant in Service is composed of Property Plant and Equipment used in the generation, transmission and distribution of electricity. The Company's accounting records segregate and separately account for generation, transmission, distribution and general plant assets. Included in general plant assets are buildings, vehicles, computer hardware and software, and other equipment necessary to support the operations of the utility.

5.2.1 Net Plant Additions

Table 5.2.1-1 below sets out the forecast Plant in Service for 2011 through 2013. It also provides 2010 actual Plant in Service data for the purpose of comparison.

Plant in Service is forecast to increase at an average level of about eight percent during 2011 through 2013, reaching approximately $1,746 million by December 31, 2013. Plant Additions in 2010 and 2011 are relatively consistent at $142 million. The decline in 2012 to $98 million is due to several large, multi-year projects, namely the Okanagan Transmission Reinforcement and Corra Linn Upgrade Life Extension projects being substantially competed in 2011.

In 2013 Plant Additions increases to $138 million primarily due to the completion of several major transmission and general plant projects, namely, the Grand Forks Transformer Addition, Kootenay Long Term Facility Strategy, Trail Buildings Purchase and Advanced Metering Infrastructure (AMI) projects. The completion of these projects cumulatively contributes more than $65 million or approximately 47 percent of additions to Plant in Service in 2013.

Table 5.2.1-2 indicates actual and forecast Plant in Service for major projects during the 2010 through 2013 timeframe.

Table 5.2.1-1 Actual and Forecast Utility Year End Plant in Service

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	**Plant additions:**				
2	Hydraulic Production Plant	21,708	35,046	11,537	2,766
3	Transmission Plant	53,488	61,221	35,441	32,793
4	Distribution Plant	57,121	26,267	37,173	34,932
5	Genaral Plant	10,079	19,441	14,094	67,697
6	**Total Plant Additions**	**142,396**	**141,975**	**98,246**	**138,188**
7	**Plant Retirements:**				
8	Hydraulic Production Plant	(659)	(659)	(659)	(659)
9	Transmission Plant	(7,434)	(7,434)	(7,434)	(7,434)
10	Distribution Plant	(3,255)	(3,255)	(3,255)	(3,255)
11	Genaral Plant	(908)	(908)	(908)	(908)
12	**Total Plant Retirements**	**(12,256)**	**(12,256)**	**(12,256)**	**(12,256)**
13	**Net Additions to Plant:**	**130,141**	**129,720**	**85,990**	**125,932**
14	**Year End Plant in Service:**				
15	Plant in Service, January 1	1,273,476	1,403,617	1,533,336	1,619,327
16	**Plant in Service, December 31**	**1,403,617**	**1,533,336**	**1,619,327**	**1,745,259**

Table 5.2.1-2 Major Project Implementation - Year End Plant in Service 2011-13

		Forecast 2011	Forecast 2012	Forecast 2013	Total
			($000s)		
1	Corra Linn U1 Life Extension (replace Turbine)	16,065			16,065
2	Corra Linn U2 Life Extension (replace Turbine)	15,453	3,983		19,436
3	Okanagan Transmission Reinforcement	46,468	4,187		50,655
4	PCB Environmental Compliance		10,749	11,022	21,771
5	Grand Forks Transformer Addition			7,205	7,205
6	Kootenay Long Term Facility Strategy		1,314	15,686	17,000
7	Trail Buildings Purchase			10,000	10,000
8	Advanced Metering Infrastructure			32,432	32,432
9	**GRAND TOTAL**	**77,987**	**20,233**	**76,345**	**174,565**

Overall, FortisBC's capital expenditures reflect the commitment of the utility to maintain the reliability and security of supply of electricity to its customers. The Company's 2012 – 2013 Capital Expenditure Plan (2012-13 Capital Plan) is presented in greater detail in Tab 6 of this Application.

5.2.2 Allowance for Funds Used During Construction

AFUDC is the financing cost (both the debt and the equity components) incurred during the period of construction.

When a component of a plant or project is placed in operation or is completed and can be placed in service but the construction work as a whole is incomplete, the cost of that part of the property placed in operation is transferred to Plant in Service, and AFUDC on that component ceases. AFUDC on the cost of that part of the plant which is incomplete is continued as a charge to construction until such time as it is transferred to Plant in Service. For administrative ease, the Company applies AFUDC to projects that are greater than $0.1 million and more than three months in duration. The AFUDC rate is equal to the weighted Return on Equity plus the after tax Cost of Debt.

The estimated AFUDC rate for 2012 through 2013 remains at the approved 2010 and 2011 level of 6.7 percent (rounded), as calculated in Table 5.2.2 below.

Table 5.2.2 Calculation of AFUDC Rate for 2012-13

		Approved 2010	Approved 2011	Forecast 2012	Forecast 2013
1	Proportion of Debt	60.00%	60.00%	60.00%	60.00%
2	Weighted Average Cost of Debt	6.28%	6.18%	6.01%	5.99%
3	Income Tax Rate	28.50%	26.50%	25.00%	25.00%
4	Tax-Effected Debt Component	2.70%	2.72%	2.71%	2.69%
5	Proportion of Equity	40.00%	40.00%	40.00%	40.00%
6	Return on Equity	9.90%	9.90%	9.90%	9.90%
7	Equity Component	3.96%	3.96%	3.96%	3.96%
8	**AFUDC Rate (rounded)**	**6.70%**	**6.70%**	**6.70%**	**6.70%**

5.2.3 CWIP

CWIP refers to capital projects which are under construction and not yet in service. On March 9, 2007 the Commission by the way of Order G-20-07 directed the Company to exclude CWIP subject to AFUDC from Rate Base for the purpose of determining revenue requirements. Consequently, CWIP included in Rate Base represents construction work in progress for projects that are less than three months in duration and less than $0.1 million. Projects over this threshold attract AFUDC, and are not included in Rate Base until they are transferred to Plant in Service to ensure customers do not pay until the assets are providing the intended benefit.

5.2.4 Contributions in Aid of Construction (CIAC)

FortisBC has an obligation to serve new customers in its service area. The Company has a Commission approved electric tariff that provides for new services to be installed up to a specified level of investment. If the cost of the extension exceeds the allowed level of investment then a CIAC is required from the customer. This contribution avoids other customers from subsidizing the cost of the extension.

As indicated above, CIACs are entirely customer driven and are forecast to be 50 percent of the new connection cost during 2012 and 2013. CIACs are deducted in the calculation of Rate Base as shown in Table 5.1.1. The net book value of CIAC for the period 2010 through 2013 is shown in Table 5.2.4 below.

Table 5.2.4 Contributions in Aid of Construction - 2010-13

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Nets Book Value Jan 1	129,032	136,400	143,777	154,748
2	Accumulated Depreciation Jan 1	(38,765)	(42,636)	(46,728)	(50,107)
3	Additions	7,368	7,378	10,971	10,694
4	Depreciation	(3,871)	(4,092)	(3,379)	(3,637)
5	Net Book Value Dec 31	**93,763**	**97,049**	**104,641**	**111,698**

5.3 ACCUMULATED DEPRECIATION AND AMORTIZATION

Section 56 of the *Utilities Commission Act* (the Act) provides for the depreciation and amortization of assets, so that the capital costs of assets are expensed as a cost of service over their useful lives. Depreciation expense for the year is added to Accumulated Depreciation and Amortization, net of retirements. Accumulated Depreciation and Amortization is a reduction to Rate Base.

For the period 2010 to 2011, depreciation is based on a composite depreciation rate of 3.2 percent as approved by Order G-58-06. FortisBC has prepared its 2012 and 2013 Revenue Requirements based on the results of an updated Depreciation Study (2011 Depreciation Study) included as Appendix J to this Application. The 2009 Depreciation Study was prepared using the Average Service Life (ASL) of the assets, which is consistent with the Depreciation Study filed with the 2006 RRA (2006 Depreciation Study) and is considered acceptable under both pre-changeover Canadian Generally Accepted Accounting Principles (CGAAP) and US GAAP. The Company is requesting approval to apply these rates for depreciation purposes. The Company is also requesting approval to continue maintaining its accounting treatment for costs of removal and is not requesting a provision for negative salvage in rates at this time.

A detailed discussion regarding Depreciation is presented in Section 4.7 of Tab 4. Table 5.3 below summarizes forecast Accumulated Depreciation and Amortization by asset classification for 2011 through 2013. It also provides 2010 actual for the purpose of comparison.

Table 5.3 Accumulated Depreciation and Amortization (2010-13) as at December 31

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	**Opening Balance of Accumulated Depreciation Jan 1**				
3	Hydraulic Production Plant	27,208	29,233	31,543	35,284
4	Transmission Plant	19,366	17,381	17,861	19,989
5	Distribution Plant	191,117	203,212	219,523	234,203
6	General Plant	58,666	67,381	76,473	87,406
7	**Total Accumulated Depreciation**	**296,357**	**317,207**	**345,400**	**376,881**
8	**Opening Balance of Accumulated Amortization Jan 1**				
9	Utility Plant Acquisition Adjustment	4,838	5,024	5,210	5,396
10	Leasehold Improvements	2,054	2,526	3,097	3,801
11	Rate Stabilization Adjustment	(1,865)	(1,554)	(1,243)	(932)
12	**Total Accumulated Amortization**	**5,027**	**5,996**	**7,064**	**8,265**
13	**Depreciation Expense**				
14	Hydraulic Production Plant	3,554	4,023	4,690	4,906
15	Transmission Plant	8,569	9,943	11,477	12,367
16	Distribution Plant	19,296	20,850	20,981	21,788
17	General Plant	9,558	10,326	11,961	12,842
18	**Total Depreciation Expense**	**40,977**	**45,142**	**49,109**	**51,903**
19	**Amortization Expense**				
20	Utility Plant Acquisition Adjustment	186	186	186	186
21	Leasehold Improvements	472	571	704	107
22	Rate Stabilization Adjustment	311	311	311	311
23	**Total Amortization Expense**	**969**	**1,068**	**1,201**	**604**
24	**Charges Less Recoveries**				
25	***Retirements***				
26	Hydraulic Production Plant	(659)	(659)	(659)	(659)
27	Transmission Plant	(7,434)	(7,434)	(7,434)	(7,434)
28	Distribution Plant	(3,255)	(3,255)	(3,255)	(3,255)
29	General Plant	(908)	(908)	(908)	(908)
30	**Total Retirements**	**(12,256)**	**(12,256)**	**(12,256)**	**(12,256)**
31	***Cost of Removal***				
32	Hydraulic Production Plant	(870)	(1,054)	(290)	(181)
33	Transmission Plant	(3,120)	(2,029)	(1,915)	(2,045)
34	Distribution Plant	(3,946)	(1,285)	(3,047)	(1,651)
35	General Plant	64	(326)	(120)	(138)
36	**Total Cost of Removal**	**(7,872)**	**(4,693)**	**(5,372)**	**(4,015)**
37	**Accumulated Depreciation & Amortization Dec 31**	**323,203**	**352,464**	**385,146**	**421,382**

5.3.1 Charges Less Recoveries

Charges Less Recoveries includes Retirement of Assets and Cost of Removal of the asset as indicated in Table 5.3 above.

5.3.1.1 RETIREMENT OF ASSETS

Retirements of assets occur when plant reaches the end of its service life. Retirement of assets may also occur from causes not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions. Such causes include unusual casualties such as fire, storm, flood, etc., or obsolescence.

The retirement of assets during 2011 through 2013 are forecast at 2010 levels of approximately $12 million per year.

5.3.1.2 COST OF REMOVAL

FortisBC incurs cost of removal, also referred to as negative salvage, in conjunction with executing its capital expenditure plan. Since utility assets are normally replaced or upgraded before they fail, removal and disposal costs are incurred at the end of the service life of the asset. There are also instances when costs of removal must be incurred when an item of plant suddenly fails. Costs of removal are prudent and necessary costs incurred as part of providing service to customers. The forecast amounts reflect the expected expenditures of removing existing infrastructure less any salvage credits for scrap material sold or returned to inventory for reuse.

The actual cost of removal for 2010 was $7.9 million. The Company is requesting inclusion of $4.7 million of cost of removal in Rate Base during 2011 (detail of which is provided in Table 7B-1 found at Tab 7. During 2012-13 cost of removal is forecast at $5.4 million and $4.0 million respectively.

The actual and forecast cost of removal values during 2010 through 2013 have been indicated in Table 5.3 above.

5.3.2 Plant Acquisition Adjustment

Pursuant to the "Sale of Surplus Power Service and Exemption Order" dated July 28, 1982, the Company acquired from Teck Metals Ltd. (Teck) Plants No. 2, 3 and 4 for $20 million, with the purchase price allocated between real property, dams and equipment, and buildings. The Company paid a premium of $11.9 million over Teck's net book value. In the 1984 Rate Revision Decision (Order G-37-84), the Commission ordered FortisBC to account for the acquisition premium in accordance with the Uniform System of Accounts and that an amount of $11.9 million be recorded as a Utility Plant Acquisition Adjustment, and amortized over 64 years, or $186,000 per year.

Table 5.3 above includes the amortization of the Plant Acquisition Adjustments at $186,000 per year for the years 2010 through 2013.

5.3.3 Rate Stabilization Adjustment

In 2000 the Rate Stabilization Adjustment (RSA) was instituted in order to ensure that tariff rates would not increase more than five percent annually during the period 2000 through 2002. Commission Order G-134-99 approved the Rate Stabilization provision. Subsequently, the Negotiated Settlement Agreement for the Company's 2006 Revenue Requirements, approved by Commission Order G-58-06 stipulated that the balance of the RSA of $3.1 million is to be amortized over a ten-year period beginning in 2006.

Table 5.3 above includes the amortization of the RSA of $311,000 per year for the years 2010 through 2013.

5.4 DEFERRED CHARGES AND CREDITS

Deferred Charges and Credits are costs or credits that will be recorded in expense, income, or capital in future periods. For a regulated utility the treatment of Deferred Charges or Credits is subject to Commission approval. Pursuant to Commission Order G-52-05, Deferred Charges are recorded net of income tax with the exception of Preliminary and Investigative Charges which are either charged to capital or expensed and are not tax-effected. Tax rates applicable to 2011 additions are 26.5 percent and for 2012 and 2013 additions they are 25.0 percent. Deferred Charges are summarized in the tables below:

Table 5.4-1 Deferred Charges and Credits 2011

		Dec 31, 2010	Additions / Transfers	Amort/Transf to Other Acct	Amort.	Dec 31, 2011
				($000s)		
1	Demand Side Management	8,433	5,396	-	(1,366)	12,463
2	Preliminary and Investigative Charges	2,435	1,836	(460)	-	3,811
3	Deferred Regulatory Expense	(358)	(2,594)	2,768	(722)	(905)
4	Other Deferred Charges and Credits	1,788	(722)	(57)	(766)	243
5	Deferred Debt Issue Costs	4,399	(224)	-	(378)	3,797
6	**DEFERRED CHARGES (RATE BASE)**	**16,697**	**3,692**	**2,251**	**(3,233)**	**19,408**
7	Total Deferred Charges (Non Rate Base)	920	881	-	-	1,801
8	**TOTAL DEFERRED CHARGES**	**17,617**	**4,573**	**2,251**	**(3,233)**	**21,209**

Table 5.4-2 Deferred Charges and Credits 2012

		Dec 31, 2011	Additions / Transfers	Amort/Transf to Other Acct	Amort.	Dec 31, 2012
				($000s)		
1	Demand Side Management	12,463	5,798	-	(1,771)	16,490
2	Preliminary and Investigative Charges	3,811	1,937	(2,514)	-	3,234
3	Non-Controllable Items Variances	-	-	-	-	-
4	Deferred Regulatory Expense	(905)	-	5,415	(1,453)	3,057
5	Other Deferred Charges and Credits	243	1,145	(892)	(880)	(384)
6	Deferred Debt Issue Costs	3,797	(98)	-	(364)	3,335
7	**DEFERRED CHARGES (RATE BASE)**	**19,408**	**8,782**	**2,009**	**(4,468)**	**25,731**
8	Total Deferred Charges (Non Rate Base)	1,801	11	(1,812)	-	-
9	**TOTAL DEFERRED CHARGES**	**21,209**	**8,793**	**197**	**(4,468)**	**25,731**

Table 5.4-3 Deferred Charges and Credits 2013

		Dec 31, 2012	Additions / Transfers	Amort/Transf to Other Acct	Amort.	Dec 31, 2013
				($000s)		
1	Demand Side Management	16,490	5,909	-	(2,179)	20,220
2	Preliminary and Investigative Charges	3,234	775	(975)	-	3,034
3	Non-Controllable Items Variances	-	-	-	-	-
4	Deferred Regulatory Expense	3,057	150	-	(1,121)	2,086
5	Other Deferred Charges and Credits	(384)	1,365	(107)	(729)	145
6	Deferred Debt Issue Costs	3,335	1,410	-	(330)	4,414
7	**DEFERRED CHARGES (RATE BASE)**	**25,731**	**9,608**	**(1,082)**	**(4,358)**	**29,899**

5.4.1 Demand Side Management

The 2012-13 Capital Plan (Tab 6) includes DSM expenditures of $5.8 and $5.9 million ($7.7 and $7.9 million before tax) respectively. These DSM expenditures are required to continue cost-effective DSM resource acquisition by providing a range of programs targeted at the end-users of each sector, including those programs mandated under the adequacy provisions of the DSM Regulation. Details of the DSM expenditures can be found in the 2012-13 Capital Plan in Tab 6.

Deferred Demand Side Management expenditures up to and including 2005 expenditures are being amortized over an eight-year period; 2006 and subsequent expenditures are being amortized over a ten year period, consistent with the practice of BC Hydro, as agreed in the 2006 NSA approved by Commission Order G-58-06.

5.4.2 Preliminary and Investigative Charges

Expenditures incurred in this category are for the investigation into potential capital projects. Upon conclusion of these studies and subsequent approval of these projects by the Commission, the costs incurred will be transferred to the approved capital project. Costs incurred on potential projects that do not proceed will be expensed.

Preliminary and investigative charges for 2011, 2012, and 2013 are described below:

i. Long-Term Facilities Strategy 2008

The Company undertook a preliminary space analysis for the Kootenay and Kelowna areas, prompted by aging and inadequate facilities, which included appraisals, building audits and existing space analysis. In order to develop a long term strategy for both these areas, FortisBC requested and received approval in Order G-195-10 for expenditures in 2011 to complete a more detailed review of the existing owned sites and development of alternate building and site plans. The deferred balance of $0.1 million at December 31, 2010 was transferred in 2011 to the approved capital expenditures for the Kootenay Operations Centre and for the Okanagan Long Term Solution areas.

ii. Pumped Storage Hydro

FortisBC's 2012 Long Term Resource Plan (Volume 2 of the 2012 Integrated System Plan) identified Pumped Storage Hydro (PSH) as a potential resource to meet the Company's future capacity requirements. PSH facilities involve long lead times for siting, permitting and construction due to the requirement for water storage sites, therefore development activities must be pursued prudently long in advance of actual project commissioning.

FortisBC has conducted some preliminary investigations of potential PSH sites and identified two potential sites. The costs of identification and preliminary investigation of the sites is $0.227 million. The Company is not seeking to amortize the balance of $0.2 million during the period under review and will seek disposition in a subsequent filing.

iii. PCB Environmental Compliance

PCB (Polychlorinated Biphenyl) was historically widely used in many electricity industry applications, especially as a dielectric fluid in transformers, capacitors, and other equipment. Due to PCB's toxicity and classification as a persistent organic pollutant, stringent federal regulations regarding the use have been set by Environment Canada. The costs incurred included investigation of possible PCB contamination in substation equipment to comply with regulations. The investigative costs of $0.1 million have been transferred to the PCB Environmental Compliance capital project approved by Order G-195-10.

iv. 2012 Integrated System Plan

Concurrent with the 2012-13 RRA, the company filed its 2012 Integrated System Plan, containing its long term Capital, Resource, and DSM Plans. Development costs, primarily for preliminary planning and engineering, are forecast to be $3.4 million. These costs will be transferred to the approved capital projects over the five year period 2012 to 2016. The Company expects to file its next long term capital expenditure plan for the period beginning in 2017.

v. 2011 Capital Expenditure Plan

The investigative funds of $0.2 million used to prepare the 2011 Capital Expenditure Plan are being absorbed in the 2011 capital program.

vi. Plants 1-4 (P1-P4) Capital Sustainment

The P1-P4 Sustaining Capital budget in Investigative Spending is for project planning and engineering. This includes the development of more investigation and development of detailed project scopes and cost estimates.

FortisBC forecasts $0.03 million in each of 2012 and 2013 for these investigative costs which will be transferred to the associated capital projects once construction begins.

vii. Kelowna Bulk Transformer Capacity Addition

The Company expects to incur $0.3 million in 2011 and 2012 for preliminary engineering in the preparation of a CPCN application for the Kelowna Bulk Transformer Capacity Addition. This project is described in Section 3.1.4 of the 2012-13 Capital Plan in Tab 6. Following approval of the CPCN application, which is forecast to occur in 2013, the costs will be transferred to the capital project.

viii. Advanced Metering Infrastructure Project

These investigative funds were incurred in order to prepare the AMI CPCN to be filed in 2011. As negotiated in the Company's past annual revenue requirements, the costs of the AMI program development have been held in a Non-Rate Base deferral account. The Company is requesting these funds, forecast at $1.8 million, to be moved to a Rate Base deferral account in 2012. Subject to approval of the CPCN application, the funds will be transferred into the AMI capital project in 2012.

ix. 2014-2015 Capital Expenditure Plan

The Company expects to file a two-year Capital Expenditure Plan in mid-2013. Preliminary investigation and engineering costs are estimated at $0.8 million. The costs will be absorbed in the 2014-15 capital projects.

5.4.3 Non-Controllable Items Variances

The Company is proposing to introduce Non-Controllable Item Deferral Accounts to be used for expenditures which are either outside of the Company's control or where the Company has limited ability to influence costs which should appropriately be borne by customers. The majority of these have been previously approved as flow-through or as "Z-factors" eligible for deferral under the Company's existing 2007-2011 Performance Based Regulation (PBR) Plan.

The Company proposes the variance deferral accounts described below. Forecast balances for 2012 and 2013 are nil.

i. Power Purchase Expense Variance Deferral Account

FortisBC proposes a deferral account to capture variances between forecast and actual power purchase expense. Utilizing the requested deferral account, 2012 and 2013 variances from all power purchase sources would be netted in a single account to be amortized into rates in 2014. A more detailed description of this deferral account is described in Tab 4, Section 4.1.5 of this RRA.

ii. Revenue Variance Deferral Account

To the extent that power purchase expense variance resulting from a difference in sales load between forecast and actual are adjusted, it is necessary to match this treatment by means of a deferral account to flow through variances in sales revenue. The Company proposes to amortize one third of any balance in this account at December 31, 2013 over three years beginning in 2014. A more detailed description of this deferral account is described in Tab 4, Section 4.1.5 of this RRA.

iii. Income Tax Variance Deferral Account

At any time, the Company can face uncontrollable changes in tax laws or accepted assessing practices in respect of federal income tax, provincial income tax, provincial sales taxes or any other tax that may be imposed. For purposes of the 2012 and 2013 Revenue Requirement, the Company is seeking an Income Tax Variance deferral account to capture and accumulate variances from forecast, as described in Tab 4, Section 4.6.2 of this RRA. The amortization term of any accumulated variances will be proposed as part of the 2014 RRA.

iv. HST Removal or Reform Variance Deferral Account

During 2011, a referendum on whether the provincial voters are in favour of extinguishing the HST and reinstating the PST in the province of British Columbia is planned, as described further in Tab 4, Section 4.6.3 of this RRA. Should there be implications that result from the extinguishment or modification of the HST that are determined subsequent to the approval of the final 2012-13 rates, the Company is requesting approval of the related costs to be included in a Rate Base deferral account. An amortization term of any accumulated variances will be proposed as part of the 2014 RRA.

v. Property Tax Asset Variance Deferral Account

The BC Assessment Authority is undertaking a review of the valuation of legislated electrical system rates for property tax purposes. This review could potentially impact FortisBC and result in a variance from the property tax amounts forecast in FortisBC's 2012 and 2013 Revenue Requirements as described further in Tab 4, Section 4.6.1 of this RRA. The Company is seeking a Property Tax Variance deferral account related to the BC Assessment Authority's review. An amortization term for any accumulated variances will be proposed as part of the 2014 RRA.

vi. Interest Expense Variance Deferral Account

To avoid potential gains or losses on forecasting interest expense, for the 2012 and 2013 forecast period FortisBC is seeking an Interest Expense variance deferral account and is proposing to accumulate variances from forecast, as described further in Tab 4, Section

4.7.1 of this RRA. This proposed deferral account would capture all variances relating to long and short-term interest expense, including financing fees. An amortization term for any accumulated variances will be proposed as part of the 2014 RRA.

vii. Pension and Other Post-Employment Benefits Expense Variance

Changes in the accounting expense related to both Pension and Other Post Employment Benefit costs can result from various factors such as performance of pension plan investments, external factors affecting global financial markets, changes in plan membership, and changes in accounting requirements, all of which are substantially out of the Company's control. Additionally, since the Company is required to use a measurement date of December 31, under both US GAAP and International Financial Reporting Standards (IFRS), to determine the employee future benefit costs for 2012 and 2013, the projected pension and other post employment expense will likely vary from what is forecast in this 2012-13 RRA. The Company is requesting that all variances from forecast related to 2012 and 2013 Pension and Other Post Employment Benefits expense, as described further in Tab 2, Section 2.1.1 of this RRA, are accumulated in a Pension and Other Post Employment Benefits Expense Variance deferral account. An amortization term for any accumulated variances will be proposed as part of the 2014 RRA.

viii. Insurance Expense Variance Deferral Account

Insurance expenses may differ significantly from the levels forecast, primarily due to changes in economic factors outside of the Company's control, as well as in increasing level of copper theft. Global events can influence insurance expense and the impact of this type of event cannot be reasonably incorporated into insurance forecasts, therefore a deferral account to capture the difference between actual and forecast insurance expense, as described further in Tab 4, Section 4.3.4 of this RRA, is requested. An amortization term for any accumulated variances will be proposed as part of the 2014 RRA.

ix. Extraordinary Costs (Z Factor) variance Deferral Account

The Company is proposing a variance deferral account to permit the recovery from or refund to customers of extraordinary costs outside of "steady state" operations, excluding those deferral accounts already requested for approval above. Such circumstances for inclusion in this deferral account would include directives and decisions made by the Commission or other competent regulatory agencies, including the decisions related to capital plan approval processes, acts of legislation or regulation of government, changes due to GAAP, Force

Majeure events or other extraordinary events. An amortization term of any accumulated variances will be proposed as part of the 2014 RRA.

5.4.4 Deferred Regulatory Expenses

Expenses incurred in regulatory proceedings such as rate setting or other Commission proceedings, including the costs of participating in the proceedings of other utilities when the Company is required to represent the interests of its customers are deferred until approved by the Commission. Also included are amounts arising from the incentive mechanisms, which are used to adjust rates in subsequent years.

i. 2009, 2010 and 2011 Flow-through and ROE Sharing Mechanism Adjustments

The 2009 Flow-through contributes a true-up of $1.1 million to 2011. The 2010 and 2011 Flow-through and ROE Sharing Mechanism Adjustments serve to reduce 2012 Revenue Requirements by $5.4 million. The 2010 true-up contributes $0.4 million while a further $5.0 million is from 2011 adjustments ($2.4 million for 2011 flow-through and $2.6 million for 2011 ROE Sharing). Further detail is described in Tab 7, Tables 2 – H – 1 and 2 – H – 2.

ii. Implementation of New Rate Structures

Implementation of new rate structures include expenditures that are necessary to modify the FortisBC Customer Information System and bill formatting software to accommodate the new rate structures for Rate Schedules 20, 21, 31, 40 and 41 as approved by Order G-24-11. The forecast expenditures of $0.02 million ($0.03 million before tax) include the cost of preparing bill inserts and other information material for these customer classes. The Company is requesting approval to fully amortize these costs in 2012.

iii. Shaw Application for Transmission Facility Access

On October 26, 2009, Shaw Cablesystems Ltd. and Shaw Business Solutions Inc. (collectively, Shaw) applied to the Commission for an order granting them access to FortisBC’s transmission facilities. The application followed FortisBC’s filing of a Writ and Statement of Claim in the British Columbia Supreme Court in regard to disputes concerning the license contract which sets out the terms and conditions upon which Shaw may attach its own facilities to FortisBC's transmission poles. Commission Order G-184-10 concerning the Company’s 2011 RRA approved the deferral of costs related to Shaw’s application to the Commission.

The Commission set down a regulatory process to address, among other issues, its jurisdiction under section 70 of the Utilities Commission Act to hear the application. By way of Order G-24-10 the Commission determined that it has jurisdiction to and would hear the application, and on March 17, 2010, the Commission dismissed an application by FortisBC for a reconsideration of G-24-10.

FortisBC also served a Leave to Appeal application from Orders G-24-10 and G-63-10 to the BC Court of Appeal, which was granted on June 10, 2010. FortisBC then applied to the Commission for an order suspending all processes related to the Shaw Application pending the outcome of the appeal, which will determine the issue of the Commission's jurisdiction. By Order G-114-10 dated June 30, 2010, the Commission suspended the Shaw Application proceeding and denied Shaw's request for interim relief allowing use of FortisBC's transmission facilities, pending the BC Court of Appeal decision.

The BC Court of Appeal on December 6, 2010 dismissed FortisBC's appeal and decided that the Commission has jurisdiction under section 70 to hear Shaw's application. On April 15, 2011, FortisBC and Shaw reached an agreement resolving their dispute. This agreement resulted in additional pole contact revenues, as described further in Section 4.8.1) that will flow back to customers in 2012.

The Company has incurred costs related to Shaw's application to the Commission process of $0.2 million ($0.3 million before tax) which it proposes to amortize in 2012.

iv. Tariff Amendment – Adaptive Street Lighting

FortisBC anticipated applying to the Commission in 2011 to amend Rate Schedule 50 – Lighting to charge customers whose street lighting fixtures are equipped with automated dimming controls (ADC) a reduced amount for the period during which the lights are dimmed. Since then, the principle vendor for the ADC system has entered into bankruptcy proceedings. FortisBC incurred development costs of approximately $0.002 million ($0.003 million before tax) for the proposed tariff amendment, which was expensed in 2011 once it was determined that the proposed tariff amendment would not be submitted to the Commission in 2011.

v. Residential Inclining Block (RIB) Rate and Industrial Stepped Rate Applications

On October 19, 2010, the Commission issued Order G-156-10 regarding the Company's 2009 Cost of Service Analysis and Rate Design Application (2009 COSA and RDA). FortisBC was directed to, *"…develop a plan for introducing residential inclining block rates that also incorporates a lower Basic Charge in the immediate future and file an RIB rate application with the Commission no later than March 31, 2011"* and to "*initiate consultations with its industrial customers with a goal to introduce a stepped rate for transmission service similar to RS 1823 of BC Hydro"*. On December 17, 2010, the Company filed additional information in compliance with Order G-156-10 (Compliance Filing). In the Compliance Filing, FortisBC requested approval of a deferral account in which to capture the costs related to the development of the RIB Rate Application. This deferral account was approved by Commission Order G-24-11. The deferred amount is forecast to be approximately $0.07 million ($0.1 million before tax) and FortisBC is requesting approval to fully amortize these costs in 2012.

vi. Irrigation Rate Payer Group Consultation and Load Research

These costs are related to segmenting the Irrigation class customers (Rate Schedules 60 and 61) into subgroups (such as farms, wineries and irrigation districts), and then installing interval metering for a sample of each sub-group. This research is in compliance with Order G-156-10 and will enable FortisBC to consult with Irrigation customers with respect to eligibility for service under Rate Schedules 60 and 61, and will also allow more accurate determination of the costs of serving this customer class. The deferred amount is forecast to be approximately $0.07 million ($0.1 million before tax) and FortisBC is requesting approval to fully amortize these costs in 2013.

vii. 2010 Revenue Requirements

2010 Revenue Requirements Application costs of $0.05 million ($0.08 million before tax) are being amortized in 2011 in accordance with Commission Order G-184-10.

viii. 2011 Revenue Requirements

2011 Revenue Requirements Application costs were deferred pursuant to Order G-162-09. The Company requests approval to amortize these forecast costs in the amount of $0.05 million ($0.08 million before tax) in 2012.

ix. 2014 Revenue Requirements

FortisBC is requesting approval to defer costs in 2013 for its 2014 Revenue Requirements application. At this time the Company estimates the application costs will be approximately $0.08 million ($0.1 million before tax). The Company will apply for disposition of these costs in a future application.

x. 2014-15 Capital Expenditure Plan Regulatory Costs

FortisBC expects that it will file a two-year Capital Expenditure Plan for the period 2014–2015, and is requesting approval to defer the costs of the regulatory review process, estimated at $0.08 million ($0.1 million before tax) in 2013. The Company requests approval to defer these costs and will apply for disposition in a future application.

xi. Section 71 Filing (Waneta Expansion Power Purchase Agreement)

FortisBC filed an application pursuant to Section 71 of the Utilities Commission Act for approval of a Capacity Purchase Agreement with Waneta Expansion Power Corporation. Costs are being amortized over three years starting in 2011 in accordance with Commission Order G-184-10.

xii. Cost of Service Analysis and Rate Design Application

On October 30, 2009, FortisBC submitted its 2009 COSA and RDA. A revised COSA was submitted on May 27, 2010. An oral public hearing was conducted from May 3 to May 7, 2010. After the filing of written argument by the Company and some interveners, the Commission held an additional oral argument phase on September 7, 2010. The Commission issued Order G-156-10 on October 19, 2010, the effect of which was to extend the regulatory process associated with the Application. The Company filed, as directed, a revised COSA on November 19 for which Commission issued Order G-196-10 on December 17, 2010. In addition, a further Compliance Filing was ordered, which the Company filed on December 19, 2010. Finally, the original Decision (G-156-10) was the subject of a Reconsideration Application Filed by Zellstoff-Celgar Limited Partnership on December 3, 2010. The Reconsideration Application was denied by the Commission Order G-3-11 on January 12, 2011. The Cost of Service and Rate Design Application costs of $1.5 million ($2.1 million before tax) have been deferred and are being amortized over four years starting in 2011 in accordance with Commission Order G-184-10.

xiii. BC Hydro Amendment to 3808 Power Purchase Agreement (PPA) Proceedings

Costs associated with the BC Hydro hearing requesting the Commission to amend Section 2.1 of the PPA between BC Hydro and FortisBC are being amortized over three years starting in 2010 in accordance with Commission Order G-162-09.

xiv. Section 5 Provincial Transmission Inquiry

In 2009 the Commission established an inquiry into the province's transmission infrastructure and long-term capacity needs, pursuant to the Utilities Commission Act. The relevant sections of the Act were repealed on June 3, 2010 and on June 4, 2010 the Commission issued Order G-98-10 cancelling the Section 5 Inquiry. FortisBC incurred costs of $0.06 million ($0.09 million before tax), which are being amortized in 2011 in accordance with Commission Order G-184-10.

xv. Renewal of BC Hydro PPA

FortisBC's PPA with BC Hydro expires in 2013. FortisBC has been attempting to negotiate a renewal of the PPA since October 2005

While no agreement has yet been reached, FortisBC and BC Hydro continue to seek resolution of the issue. The Company forecasts spending $0.2 million ($0.3 million net of tax).

The Company also requests to begin amortizing the costs over a five year period beginning in 2012.

xvi. 2012 Integrated System Plan and 2012–2013 Revenue Requirements

Concurrently with this application, FortisBC filed its 2012 Integrated System Plan, containing its long-term Capital, Resource, and DSM Plan.

The 2012-2013 Revenue Requirements is the first cost of service revenue requirements application since 2005. The Integrated System Plan components, likewise, have not been comprehensively updated since that time. Deferral of the costs was approved by Order G-184-10. As provided in Order G-184-10, the deferred costs associated with the Company's 2009 Resource Plan have been combined with the ISP deferral account. The Company forecasts expenditures in the amount of approximately $2.4 million ($3.3 million before tax) in 2011. These amounts include a provision for the review of part or all of the applications by way of an oral public hearing.

The Company also requests approval to amortize these costs over five years beginning in 2012.

xvii. BC Hydro Waneta Transaction Application

These costs relate to BC Hydro's acquisition of a one-third interest in the Teck Metals Ltd. Waneta Dam. Costs of $0.2 million ($0.3 million before tax) are being amortized over three years beginning in 2011 pursuant to Commission Order G-162-09.

xviii. Fortis BC Utilities (formerly Terasen Utilities) Return on Equity (ROE) and Capital Structure Application

Fortis BC Utilities ROE application costs are FortisBC's costs for participating in the Fortis BC Utilities ROE automatic adjustment mechanism. Costs are being amortized in 2011 in accordance with Commission Order G-184-10.

5.4.5 Other Deferred Charges and Credits

i. Trail Office Lease Costs

Legal and other fees associated with the lease of the Trail Office are being amortized over the lease term in accordance with Commission Order G-41-93.

ii. Trail Office Rental to SD20

Prepaid rental income is being amortized over the lease term in accordance with Generally Accepted Accounting Principles.

iii. Prepaid Pension Costs

In accordance with Part V of the Canadian Institute of Chartered Accountants Handbook – Pre-Changeover Canadian Generally Accepted Accounting Principles (CGAAP), FortisBC has recorded the difference between the actuarially determined pension net benefit cost and the forecast contributions paid by the Company, in a prepaid pension deferral account, on a net of tax basis, for 2011. This treatment was approved by Commission Order No. G-184-10 for 2011 and is consistent with prior years' revenue requirement applications over the PBR term.

Table 5.4.5-1 Prepaid Pension Costs

	Actual 2010	Approved 2011	Forecast 2011	Difference
	($000s)			
1 Opening Prepaid Pension Cost Balance	8,916	7,474	7,448	26
2 Less: Net benefit cost	(5,423)	(7,112)	(7,112)	-
3 Add: contributions	3,955	6,887	7,708	(821)
4 Net change for year	(1,468)	(225)	596	(821)
5 Ending Prepaid Pension Cost Balance	**7,448**	**7,249**	**8,044**	**(795)**
6 Gross change in Prepaid Pension Balance	(1,468)	(225)	596	(821)
7 Tax effect	418	60	(158)	218
8 Net change in Prepaid Pensions during year	**(1,050)**	**(165)**	**438**	**(603)**

While the 2011 pension net benefit cost is expected to remain unchanged from the amounts used to determine the approved 2011 prepaid pension cost, the 2011 forecast contributions have increased by approximately $0.8 million due to the estimated results of the actuarial valuations effective December 31, 2010. Although all the actuarial valuations for the Company's defined benefit pension plans have not yet been completed (actuarial valuations must be filed by the end of September 2011), as of the time of this filing, the Company's actuary has revised the forecast contributions for 2011 through 2013, based on the most recent data provided for the actuarial valuations. As a result, the Company is forecasting a $0.4 million ($0.6 million before tax) increase to the prepaid pension cost deferral account in 2011.

The 2012 and 2013 pension deferral amounts requested for approval are dependent on which set of accounting standards the Commission approves FortisBC to adopt for regulatory purposes effective January 1, 2012. Beginning in 2012, pre-changeover GAAP will be withdrawn by Canadian standard setters and will cease to exist as a financial reporting option.

This leaves two available options for FortisBC to prepare its regulatory filings beginning in 2012: (1) adopting a modified version of IFRS with deferral accounting; or (2) adopting US GAAP, which permits the continued recognition of rate-regulated accounting. Current IFRS does not permit deferral accounting. As described in further detail in Tab 2, on February 9, 2011, the Fortis BC Utilities, including FortisBC, applied to the Commission for adoption of US GAAP for regulatory accounting purposes effective January 1, 2012. As at the time of this filing, FortisBC is still awaiting Commission approval to adopt US GAAP for regulatory purposes. A comparison of pension accounting balances between US GAAP and IFRS, using deferral accounting, is shown below.

Since US GAAP for pension accounting more closely reflects the pre-changeover CGAAP, which is no longer available in 2012, the prepaid pension costs and pension transitional obligation deferral accounts have been prepared under US GAAP for the 2012-13 RRA.

Table 5.4.5-2 Comparison of Pension Accounting Balances Under US GAAP and IFRS

		US GAAP (Expected)		IFRS with Deferral Accounting	
		Deferred Charges Schedule		Deferred Charges Schedule	
		US GAAP Prepaid Pension Cost(1)	US GAAP Transitional Obligation Deferral Account(2)	IFRS Pension Liability (3)	IFRS Transitional Obligation Deferral Account(4)
		($000s)		($000s)	
1	**December 31, 2011 - Ending Balance CGAAP**	**8,044**	**-**	**8,044**	**-**
2	January 1, 2012 - Transitional Adjustment	(2,194)	2,194	(24,452)	24,452
3	Pension net benefit cost during 2012	(4,691)	-	(3,088)	-
4	Cash contributions during 2012	7,872	-	7,872	-
5	Amortization of transitional balance during 2012	-	(183)	-	(2,038)
6	Change during 2012	987	2,011	(19,668)	22,414
7	**December 31, 2012 - Prepaid (Accrued) Pension Cost**	**9,031**	**2,011**	**(11,624)**	**22,414**
8	Pension net benefit cost during 2013	(4,039)	-	(2,736)	-
9	Cash contributions during 2013	7,590	-	7,590	-
10	Amortization of transitional balance during 2013	-	(183)	-	(2,038)
11	Change during 2013	3,551	(183)	4,854	(2,038)
12	**December 31, 2013 - Prepaid (Accrued) Pension Cost**	**12,582**	**1,828**	**(6,770)**	**20,377**
13	**Change in deferred balances (net of tax effect)**				
14	Change during 2012	987	2,194	(19,668)	24,452
15	Tax effect	(247)	(549)	4,917	(6,113)
16	Net change during 2012	**740**	**1,646**	**(14,751)**	**18,339**
17	Change during 2013	3,551	-	4,854	-
18	Tax effect	(888)	-	(1,214)	-
19	Net change during 2013	**2,663**	**-**	**3,641**	**-**

The determination of the prepaid pension costs under US GAAP uses a methodology similar to the 2011 pre-changeover CGAAP, where the difference between the actuarially determined pension net benefit cost and forecast contributions paid by the Company is accumulated as a deferral account.

The 2012 and 2013 prepaid pension cost is comprised of the net benefit cost prepared under FAS 87, and relates to the following:

- The three registered defined benefit plans sponsored by the Company (the FortisBC IBEW Pension Plan (the IBEW Plan), the COPE FortisBC Pension Plan (the COPE Plan), and the FortisBC Retirement Income Plan (the FRIP)); and
- Supplemental pension arrangements for current and former executives.

The cash contributions have been forecast by the Company's actuary based on the most recent data provided for the defined benefit plans' actuarial valuations as of December 31, 2010.

Additionally, the 2012 change in this Prepaid Pension Cost account balance will reflect a reduction of $2.2 million, the offset which is recognized in the Pension Transitional Obligation Deferral Account, a separate Rate Base deferral account. The Company is requesting approval to recognize the total Prepaid Pension Costs as a Rate Base deferral account, on a net of tax basis, for 2012 and 2013.

The Company is forecasting a $0.7 million ($1.0 million before tax) increase to prepaid pension cost account in 2012 and a $2.7 million ($3.6 million before tax) increase to this account in 2013.

IFRS Prepaid (Accrued) Pension Costs

The explanation of the IFRS Prepaid (Accrued) Pension Costs is for purposes of comparison to US GAAP and has not been included in any of the financial schedules as part of the determination of the 2012/13 Revenue Requirements application. For comparison to US GAAP, FortisBC has estimated the IFRS prepaid (accrued) pension costs using a similar methodology as the 2011 CGAAP and 2012-13 US GAAP prepaid pension costs. Under a modified IFRS scenario with deferral accounting, FortisBC would propose recording the difference between the actuarially determined IFRS pension net benefit cost and contributions paid by the Company in a Rate Base deferral account, on a net of tax basis. Additionally, the 2012 change in this account balance would reflect the initial recognition of a $24.5 million IFRS Pension Transitional Obligation Deferral Account which would be offset in a separate Rate Base deferral account discussed in the next item. Under an IFRS scenario, with deferral accounting, the Company would forecast a $14.8 million ($19.7 million before tax) increase to this liability account in 2012 and a $3.6 million ($4.9 million before tax) increase to this account in 2013.

iv. US GAAP Pension Transitional Obligation Deferral

The US GAAP Pension Transitional Obligation deferral account has been requested for inclusion in the Rate Base as part of the determination of the 2012-13 RRA. Under US GAAP, it would be necessary for FortisBC to recognize the historical cumulative difference between CGAAP and US GAAP pension net benefit costs, referred to herein as the pension transitional obligation, in the forecast amount of $2.2 million, as of January 1, 2012. This amount is comprised of the remaining unamortized net transition obligations under CGAAP (which would be fully amortized under US GAAP) and the net benefit cost for three months, resulting from the change in measurement date from September 30 to December 31 as required under US GAAP. If the adoption of US GAAP is approved for regulatory purposes, FortisBC requests approval for this forecast pension transitional obligation to be recognized as a Rate Base deferral account with an equal offset recognized against prepaid pension costs, which is also proposed for recognition as a Rate Base deferral account, as previously described above. The Company also proposes the recovery of this Pension Transitional Obligation Deferral Account over the approximate Expected Average Remaining Service Life (EARSL) of the Company's pension plans of approximately 12 years (11.5 year EARSL rounded up) to phase the transitional difference into rates. The Company is forecasting a $1.6 million ($2.2 million before tax) increase to this deferral account, offset by amortization of $0.2 million, for 2012 and a decrease of $0.2 million to this deferral account due to amortization in 2013, based on an amortization period using the approximate EARSL. Under US GAAP, there are further adjustments required to pensions other than the Prepaid Pension Costs and Pension Transitional Obligation Deferral Account previously described. For external financial reporting purposes, under FAS 158 – Employers' Accounting for Defined Benefit Pension and Other Post Retirement Benefit Plans, all accumulated unrecognized losses (gains) and all unrecognized prior service costs (credits) are recognized in Accumulated Other Comprehensive Income (AOCI) with an equal offset booked against the prepaid pension cost so that the actual funded status of the plans is shown on the balance sheet. Rather than recognize this amount in AOCI or as a Rate Base deferral account, the Company is requesting regulatory recognition and acknowledgement of a Non-Rate Base deferral account to accumulate these amounts as indicated in Appendix E. Under current US GAAP, the amount in AOCI is recycled through the pension net benefit cost, similar to pre-changeover CGAAP, which is why the amount in AOCI is not requested to be included as an amortizing Rate Base deferral account.

IFRS Pension Transitional Obligation Deferral

The explanation of the IFRS Pension Transitional Obligation Deferral is for purposes of comparison to US GAAP and has not been included in any of the financial schedules as part of the determination of the 2012-13 RRA. Under an IFRS employee future benefits scenario where the deferral of gains and losses would still be permitted, it would be necessary for FortisBC to recognize all accumulated unamortized pension actuarial gains and losses, past service costs (credits) and transitional obligations as an opening adjustment to retained earnings for external financial reporting. Also included in the pension transitional obligation would be three months of net benefit costs resulting from the change in measurement date from September 30 to December 31 as required under IFRS. If IFRS with deferral accounting were used for regulatory purposes, FortisBC would recommend that this pension Transitional Obligation Deferral Account be initially recognized as a Rate Base deferral account with an equal offset recognized against IFRS prepaid pension costs, which is also proposed for recognition as a Rate Base deferral account, as previously described. The Company would also propose the recovery of the IFRS Pension Transitional Obligation Deferral Account over the approximate EARSL of the Company's pension plans of approximately 12 years (11.5 year EARSL rounded up), the same methodology as what was proposed under US GAAP. Under a modified IFRS scenario with deferral accounting, the Company would forecast an $18.3 million ($24.4 million before tax) increase, offset by amortization of $0.9 million, in 2012 and a decrease of $2.0 million decrease to this account due to amortization for 2013 based on an amortization period using the approximate EARSL.

v. Other Post-Employment Benefits (OPEB)

In accordance with pre-changeover GAAP, FortisBC records the difference between the actuarially determined OPEB net benefit cost and the amounts actually paid by the Company to retirees as an OPEB deferral account, on a net of tax basis, for 2011. This treatment was approved by Commission Order No. G-184-10 for 2011 and is consistent with prior years' revenue requirement applications over the previous PBR term. The Company is forecasting a $2.1 million ($2.8 million before tax) increase to this liability deferral account in 2011.

Table 5.4.5-3 OPEB Liability

		Actual 2010	Forecast 2011
		($000s)	
1	CICA 3461 net benefit cost	(2,619)	(3,053)
2	Amortization of 2004 OPEB liability	(480)	(480)
3	Contributions (cash outlays)	480	730
4	Partial shortfall in accrual vs. cash	(2,619)	(2,803)
5	Phase-in rate	100%	100%
8	Net change for year	(2,619)	(2,803)
9	Opening OPEB Liability Balance	(7,702)	(10,321)
10	Ending OPEB Liability Balance	(10,321)	(13,124)
11	Gross change in OPEB Liability	(2,619)	(2,803)
12	Tax effect	746	743
13	Net change in OPEB Liability during year	(1,873)	(2,060)

The Company is forecasting a $2.1 million ($2.8 million before tax) increase to the OPEB liability deferral account in 2011 consistent with what was approved pursuant to Commission Order G-184-10. The Company's actuary has forecast the increase in OPEBs paid out for 2011 through 2013, based on the most recent data provided for the actuarial valuation. As a result the Company is forecasting a $2.1 million ($2.8 million before tax) increase to the OPEB liability deferral account in 2011.

The 2012 and 2013 OPEB obligation deferral amounts requested for approval will be highly dependent on which set of accounting standards the Commission approves FortisBC to adopt for regulatory purposes effective January 1, 2012. A comparison of OPEB accounting balances between US GAAP and IFRS, using deferral accounting, has been prepared below.

Similar to pension accounting, US GAAP for OPEB accounting more closely reflects the pre-changeover CGAAP, which can no longer be applied in 2012, therefore the OPEB liability and transitional obligation deferral accounts have been prepared under US GAAP for the 2012-13 RRA.

Table 5.4.5-4 Comparison of OPEB Balances under US GAAP and IFRS

	US GAAP (Expected)		IFRS with Deferral Accounting	
	Deferred Charges Schedule		Deferred Charges Schedule	
	US GAAP OPEB Liability(1)	US GAAP OPEB Transitional Obligation(2)	IFRS OPEB Liability(3)	IFRS OPEB Transitional Obligation(4)
	($000s)		($000s)	
1 **December 31, 2011 - Ending Balance CGAAP**	**(13,124)**	**-**	**(13,124)**	**-**
2 January 1, 2011 - Transitional Adjustment to 2005 CICA	(3,525)	3,525	(3,525)	3,525
3 January 1, 2012 - Transitional Adjustment	(1,963)	1,963	(5,351)	5,351
4 OPEB net benefit cost during 2012	(2,726)	-	(2,379)	-
5 Cash contributions during 2012	551	-	551	-
6 Amortization of 2005 CICA OPEB liabilty during 2012	-	(480)	-	(480)
7 Amortization of transitional balance during 2012	-	(164)	-	(446)
8 Change during 2012	(7,663)	4,844	(10,704)	7,950
9 **December 31, 2012 - OPEB Liability balance**	**(20,787)**	**4,844**	**(23,828)**	**7,950**
10 OPEB net benefit cost during 2013	(2,825)	-	(2,529)	-
11 Cash contributions during 2013	579	-	579	-
12 Amortization of 2005 CICA OPEB liabilty during 2012	-	(480)	-	(480)
13 Amortization of transitional balance during 2013	-	(164)	-	(446)
14 Change during 2013	(2,246)	(644)	(1,950)	(926)
15 **December 31, 2013 - OPEB Liability balance**	**(23,033)**	**4,201**	**(25,778)**	**7,024**
16 **Change in deferred balances (net of tax effect)**				
17 Change during 2012	(7,663)	5,488	(10,704)	8,876
18 Tax effect	1,916	(1,372)	2,676	(2,219)
19 Net change during 2012	**(5,747)**	**4,116**	**(8,028)**	**6,657**
20 Change during 2013	(2,246)	-	(1,950)	-
21 Tax effect	562	-	488	-
22 Net change during 2013	**(1,685)**	**-**	**(1,463)**	**-**

For each of 2012 and 2013, a portion of the change in the US GAAP OPEB liability consists of the actuarially determined US GAAP OPEB net benefit costs less forecast benefits paid out, which is a similar methodology used in the determination of the 2011 CGAAP OPEB liability. Additionally, the 2012 change in the OPEB liability account balance will reflect the initial recognition of a $3.5 million 2005 CICA transitional adjustment and a $2.0 million US GAAP transitional adjustment, both of which will be offset in a separate Rate Base deferral account as discussed in the next item. The Company is requesting approval to recognize this US GAAP OPEB liability as a Rate Base deferral account, on a net of tax basis, for 2012 and 2013. The Company is forecasting a $5.7 million ($7.7 million before tax) increase to this liability account in 2012 and a $1.7 million ($2.2 million before tax) increase to this account in 2013.

IFRS OPEB Liability

The explanation of the IFRS OPEB Liability is for purposes of comparison to US GAAP and has not been included in any of the financial schedules as part of the determination of the 2012/13 Revenue Requirements application. For comparison to US GAAP, FortisBC has estimated the IFRS OPEB liability cost using a similar methodology as the 2011 CGAAP and 2012/13 US GAAP OPEB liability. Under an IFRS scenario with deferral accounting, FortisBC would propose recording the difference between the actuarially determined OPEB net benefit cost under IFRS and forecast benefits paid by the Company in a Rate Base deferral account, on a net of tax basis. Additionally, the 2012 change in this account balance would reflect the initial recognition of a $5.4 million IFRS OPEB transitional adjustment and the $3.5 million 2005 CICA OPEB transitional adjustment. Both these items are similar in principle to the proposed US GAAP methodology and both amounts would be offset in a separate Rate Base deferral account. Under an IFRS scenario, with deferral accounting, the Company would forecast an $8.0 million ($10.7 million before tax) increase to this liability account in 2012 and a $1.5 million ($2.0 million before tax) increase in 2013.

vi. US GAAP OPEB Transitional Obligation Deferral

The US GAAP OPEB Transitional Obligation deferral account has been requested for inclusion in the Rate Base as part of the determination of the 2012/13 Revenue Requirements application. This requested Rate Base deferral account includes two components:

Firstly, under US GAAP, it would be necessary for FortisBC to recognize the historical cumulative difference between CGAAP and US GAAP OPEB net benefit costs, referred to herein as an OPEB transitional obligation, in the forecast amount of $2.0 million, as of January 1, 2012. This amount is comprised of the remaining unamortized net transition obligations under CGAAP (which would be fully amortized under US GAAP) and the net benefit cost for three months, resulting from the change in measurement date from September 30 to December 31 as required under US GAAP. The Company also proposes the recovery of this OPEB transitional adjustment over 12 years.

Secondly, the requested deferral account also includes the forecast remaining transitional obligation of $3.5 million relating to the CGAAP OPEB liability. As directed under Commission Order G-52-05, FortisBC began amortizing the accumulated CGAAP 2005 OPEB liability over the EARSL when the Company transitioned from the cash basis to accrual accounting for OPEBs, which was phased-in over a three year period. While the amortization of the CGAAP OPEB transitional obligation has been included in the OPEB expense since 2005, the actual deferral amount has not been previously recognized in Rate Base and has been tracked as a Non-Rate Base deferral account. The Company proposes to recognize the 2005 CICA OPEB transitional adjustment in the US GAAP OPEB Transitional Obligation Rate Base deferral beginning in 2012 and it will be offset by an equal amount in Rate Base included in the US GAAP OPEB Liability Account, previously described. In addition to recognizing the transitional obligation difference between CGAAP and US GAAP OPEB liabilities, it is necessary to still complete the amortization of the difference between the regulatory OPEB balance and the CGAAP OPEB balance from 2005.

If the adoption of US GAAP is approved for regulatory purposes, FortisBC requests approval that this US GAAP OPEB Transitional Obligation be recognized as a Rate Base deferral account with an equal offset recognized against the US GAAP OPEB liability, which is also proposed for recognition as a Rate Base deferral account, as previously described. The Company is forecasting a $4.1 million ($5.5 million before tax) increase to this account in 2012, partially offset by amortization of $0.6 million, and a $0.6 million decrease due to amortization for 2013.

Similar to pension accounting treatment, FAS 158 would require recognition of accumulated unamortized gains (losses) and unrecognized prior service costs (credits) in AOCI with an equal offset booked against the OPEB liability to show the actual funded status on the balance sheet. Rather than recognize this balance through AOCI or as a Rate Base deferral account, the Company is requesting regulatory recognition and acknowledgement of a non-Rate Base deferral account to accumulate these amounts as indicated in Appendix E. Under current US GAAP, the amount in AOCI is recycled back through the OPEB net benefit cost, similar to pre-changeover CGAAP, which is why the amount in AOCI is not requested to be included as an amortizing Rate Base deferral account.

IFRS OPEB Transitional Obligation Deferral

The explanation of the IFRS OPEB Transitional Obligation Deferral is for purposes of comparison to US GAAP and has not been included in any of the financial schedules as part of the determination of the 2012-13 RRA. If IFRS with deferral accounting were used for regulatory purposes, FortisBC would recommend that this OPEB Transitional Obligation

Deferral Account, similar to the pension Transitional Obligation Deferral Account as previously described, be initially recognized as a Rate Base deferral account with an equal offset recognized against IFRS OPEB liability, which is also proposed for recognition as a Rate Base deferral account, as previously described. The Company would also propose the recovery of the IFRS OPEB Transitional Obligation Deferral Account over 12 years, the same methodology as what was proposed under US GAAP. Similar to the requested US GAAP OPEB deferral account, the 2005 CICA OPEB Transitional Obligation Deferral Account would also be included in this requested deferral. Under an IFRS scenario, the Company would forecast a $6.7 million ($8.9 million before tax) increase to this account for 2012, partially offset by a decrease of $0.9 million in amortization, and a $0.9 million decrease in 2013 due to amortization.

vii. Revenue Protection

In accordance with Commission Order G-58-06 the Company is directed to report annually on the costs and tangible benefits of the Revenue Protection program.

Forecast expenditures for 2011 are $0.17 million after tax ($0.23 million before tax) which will yield approximately $0.5 million in present value benefits as shown below. Consistent with past treatment, the Company has deferred the 2011 expenditures and proposes to amortize these costs in 2012.

Table 5.4.5-6 Forecast Cost and Savings of Revenue Protection Activities

2011 Activity	Approved Cost	Forecast Cost	Forecast Annual Savings	NPV Savings*
Power Diversion Inspections	$204,000	$204,000	$95,865	$382,761
Third Party Contracts	$30,600	$30,600	$159,600	$159,600
Total	**$234,600**	**$234,600**	**$255,465**	**$542,361**

**Discounted Savings at 8% over five years*

The primary activities undertaken in 2011 are:

Power Diversion Inspections

This is the core activity of the Revenue Protection program. The identification and correction of electrical power diversions is important for several reasons:

- Public and employee safety - Power diversions require physical changes to the electric service infrastructure that are not properly inspected. This creates a potential safety hazard for both the public and employees;

- Power purchase costs - When power is diverted, power purchase costs for all ratepayers increase. The quantifiable benefits of power diversion inspections are based solely upon power purchase savings; and
- General deterrence - Power theft investigations and the criminal charges that often accompany detection send a clear message in the service area that FortisBC is committed in its mandate to deliver electricity safely at the lowest reasonable cost to customers.

Third Party Contracts

Continued focus on the various pole rental agreements was the core activity during 2011. Increasing demand for access to electric infrastructure provides opportunities for additional income to the benefit of customers.

Beginning in 2012, the costs of the Revenue Protection activities are included in Operating and Maintenance Expense in the Customer Services department.

viii. Princeton Light and Power (PLP) Computer Software

Deferred costs of PLP prior to its acquisition by FortisBC are being amortized in accordance with Commission Order G-159-06.

ix. Princeton Light and Power Deferred Pension Credit

Deferred costs of PLP prior to its acquisition by FortisBC are being amortized in accordance with Commission Order G-159-06.

x. Right of Way Reclamation (Pine Beetle Kill)

Right of Way Reclamation costs of $1.7 million ($2.5 million before tax) for the removal of danger trees killed by the pine beetle in 2008 were deferred and are being amortized over ten years in accordance with Commission Order G-147-07.

xi. International Financial Reporting Standards (IFRS)

2010 costs associated with the conversion to IFRS including research, education, training and changes to existing processes of $0.15 million ($0.2 million before tax) are being amortized in 2011 in accordance with Commission Order G-193-08.

xii. Right of Way Encroachment Litigation

The Company is expecting to defer approximately $0.09 million ($0.12 million before tax) of legal costs incurred by the end of 2011 associated with an ongoing litigation matter with a land developer in relation to certain encroachments made by the developer on one of the Company's statutory rights of way in Kelowna, British Columbia. Upon resolution of the dispute, any recovered cost will be recorded to the deferral account and the residual is to be amortized into the Company's rates pursuant to Order G-193-08. As the dispute has not yet been resolved, the residual would not be amortized prior to 2014.

xiii. Harmonized Sales Tax Implementation Project

Harmonized Sales Tax (HST) Implementation costs are associated with the implementation of HST including information system changes, training and tax service consulting costs. Costs of $0.16 million ($0.2 million before tax) are being amortized in 2011 in accordance with Commission Order G-184-10.

xiv. Asset Management

FortisBC is proposing a staged approach to the development of an Asset Management solution, as described in Section 1.1 of the 2012 Long Term Capital Plan (2012 Integrated System Plan, Volume 1). In 2012 and 2013, total expenditures of $0.6 million ($0.8 million before tax) are proposed to accommodate the development of a project team comprising internal and external resources. This project team will examine FortisBC's existing Asset Management processes and provide a comprehensive report and project cost estimate recommending changes and mapping out an implementation plan for submission in a future capital expenditure plan application. The Company will apply for disposition of the costs at a later time.

xv. DSM Study

DSM Study costs were to complete the Residential and Commercial End-Use Surveys and to initiate a Conservation and Demand Potential review. Costs of $0.18 million ($0.26 million before tax) are being amortized over three years starting in 2011 in accordance with Commission Order G-184-10.

xvi. US Generally Accepted Accounting Principles

FortisBC is planning to adopt US GAAP for financial reporting purposes effective January 1, 2012, and believe it is in the best interest of all stakeholders to also amend the system of accounting that is used as the basis for reporting to the Commission to be in accordance with US GAAP. Although the adoption of US GAAP for regulatory purposes will result in one-time conversion costs, these costs are justified as the adoption of US GAAP is reasonable and in the public interest because it is the only set of accounting principles that currently allows for the recognition of regulatory assets and liabilities. FortisBC maintains that the appropriate and prudent financial reporting standard that should be utilized is the standard that best reflects the economic and regulatory status as a public utility, and that standard is US GAAP. The adoption of US GAAP will also reduce the administrative burden and costs of reconciling from IFRS back to the regulatory records.

The application filed by Fortis BC Utilities on February 9, 2011, requested approval for FortisBC to accumulate the one-time conversion costs associated with the adoption of US GAAP during 2011 in a Rate Base deferral account to be amortized into customer rates in 2012 and 2013. These conversion costs are forecast at $0.6 million ($0.8 million before tax) and include audit, legal, advisory, and actuarial fees. FortisBC would like to amortize these costs over a two year period beginning in 2012.

xvii. Joint Pole Use Audit 2008

Under the provisions of the Company's various joint pole use agreements, the parties are required to perform an audit of the joint use pole contacts once every five years. Any unreported contacts identified during the audit result in penalty billings ranging from 3 to 5 years and sustainable revenues in succeeding years. The 2008 audit resulted in a collection of $407,000 in penalty revenue.

FortisBC's portion of the audit costs were $0.1 million ($0.2 million before tax) and are being amortized over five years beginning in 2009, as approved in Order G-193-08.

xviii. Joint Pole Use Audit 2013

Under the provisions of the Company's various joint pole use agreements, the parties are required to perform an audit of the joint use pole contacts once every five years. The last audit was in 2008 and FortisBC is requesting to defer funds of $0.2 million ($0.3 million before tax) and to begin amortization in 2013 over a five year period.

xix. Pope & Talbot Litigation

Costs of $0.17 million ($0.23 million before tax), deferred for the settlement with the US Trustee for Canadian creditors in the US Bankruptcy Court with the bankruptcy of Pope & Talbot, are being fully amortized in 2011 in accordance with Commission Order G-184-10.

xx. Mandatory Reliability Standards Project

FortisBC is incurring set-up costs in addition to capital and ongoing operating costs to become and remain compliant with the newly adopted Mandatory Reliability Standards. Deferral of these set-up costs approved by Order G-184-10, are estimated at $0.7 million ($1.0 million before tax) by yearend 2011.

The Company is requesting to amortize the costs over a five year period, beginning in 2012.

xxi. Deferred Debt Issue Costs

The Company expects to issue $120 million in unsecured debentures during 2013, with a term of 30 years. Prior to issuance in 2013, the Company will request approval to issue this debt as part of a separate debt issuance application to the Commission. The Company has previously been approved to issue unsecured debt of up to $150 million in 2004 pursuant to Commission Order G-77-04, up to $100 million in 2005 pursuant to Commission Order G-102-05 and up to $110 million in 2007 pursuant to Commission Order G-61-07. Additionally, the Company has previously issued MTN Debentures in the amount of $105 million in 2009 and $100 million in 2010 pursuant to Commission Order G-51-09 which approved FortisBC's application to issue up to $300 million from time to time, according to the terms of a Shelf Prospectus, until June 11, 2011. The 2013 debt issuance will maintain the Company's approved 60 percent debt capitalization structure and will primarily finance the Company's capital expenditure program and working capital requirements.

A significant portion of any debt issue costs are the dealer's fees. For 2013 these fees have been forecast using a 0.9 percent of the principal debt amount and using a term of 30 years. This bought deal rate is based on the Company's most recent 2009 dealers' agreement. If there is a change in the principal amount, term or type of deal (bought versus agent), the dealers' fees and related costs would be adjusted accordingly. The total debt issue costs of $1.6 million are expected to be substantially the same under either a stand-alone short form prospectus, which is how the 2005 and 2007 debentures were issued, or the first issuance under a shelf prospectus program, similar to the 2009 Medium Term Note (MTN) debentures. To choose the term of debt issue, the Company considers (1) the expected useful life of its assets, (2) the frequency of market exposure, (3) the estimated coupon rate at time of issuance compared to historical, and (4) the frequency of incurring issue costs. FortisBC will file an application for approval of the debt issuance and, subject to approval of that application, requests approval to defer the issue costs, and to amortize the costs over the term of the debt issue.

Expected expenditures related to this debt issuance are detailed below:

Table 5.4.5-7 Forecast Debt Issue Costs

		Shelf Prospectus 2013 Bought Deal Estimated $ ($000s)
1	Principal Amount	120,000
2	Professional Fees	
3	Legal Costs (including prospectus and Annual Information Form)	220
4	Auditor (French translations, comfort letters, due diligence, etc.)	67
5	French translations (prospectus and Annual Information Form)	50
6	Dealers Fees (0.9% of principal debt amount)	1,080
7	Filing Fees	38
8	Other	
9	Trustee fees (ComputerShare)	11
10	Investor presentations and Travel	26
11	Rating agency fee (Moody's and DBRS)	75
12	Special Board of Directors Meetings	20
13		1,587

FortisBC has incurred similar debt issue costs since 2005, as detailed in Table 5.4.5-8 and is amortizing the costs over the life of the debt.

Table 5.4.5-8 Debt Issue Costs, 2005 - 2010

	Series	Term (Years)	Issue Date	Debt Amount ($000s)	Yield	Debt Issue Cost ($000s)
1	Series 05-1	30	11/9/2005	100,000	5.60%	1,241
2	Series 07-1	40	7/4/2007	105,000	5.90%	1,246
3	MTN-2009	30	6/2/2009	105,000	6.10%	992
4	MTN-2010	40	11/24/2010	100,000	5.00%	941

5.5. ALLOWANCE FOR WORKING CAPITAL

Allowance for Working Capital is added to the Rate Base to recognize the lag between when revenue is earned and when the funds are received for that revenue, offset by when expenses are incurred and when the funds are released to pay for the expenses.

The Allowance for Working Capital is determined through a review of the timing differences between the provision of services or use of goods, and the exchange of funds between FortisBC and the customer or vendor. Additionally, the allowance for working capital also includes working capital funds that are unavailable for use, and excludes working capital funds that are available for use. The cumulative impact of these timing differences is added to the average value of inventory and other current assets to arrive at the Allowance for Working Capital.

The working capital allowance applied / to be applied to FortisBC Rate Base during 2010-2013 is shown below. Detailed calculations based on lead-lag days and forecast funds expected to be available / unavailable for use are provided in Tab 7 Tables 1 – E.

Table 5.5 Allowance for Working Capital 2010-13

	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
	($000s)			
Allowance for Working Capital	5,756	7,361	1,654	1,007

5.6 ADJUSTMENT FOR CAPITAL EXPENDITURES

Utility Rate Base is determined using weighted average capital expenditures for the period. To provide for the weighted average, an adjustment for capital expenditure is made as follows:

i. The weighted expenditure for each month is calculated by multiplying the monthly capital expenditures by the average number of months remaining for the year

ii. The weighted expenditures for each month are then summed to calculate the weighted average.

iii. Total capital expenditures are then divided by two to calculate the simple average

iv. The simple average is then subtracted from the weighted average.

v. Difference between the weighted expenditure and the simple average of the expenditures provides the timing impact of the expenditure profile on funding requirements.

Table 5.6 Adjustment for Capital Expenditure (2010-2013)

($000s)

		Actual 2010		Forecast 2011		Forecast 2012		Forecast 2013	
Plant additions:	**Months in Rate Base**	**Plant in Service**	**Weighted Value**	**Plant in Service**	**Weighted Value**	**Plant in Service**	**Weighted Value**	**Plant in Service**	**Weighted Value**
1 January	11.50	1,509	1,446	1,061	1,017	4,115	3,943	6,011	5,760
2 February	10.50	17,460	15,278	2,605	2,279	4,115	3,600	6,011	5,259
3 March	9.50	3,544	2,806	41,220	32,632	4,115	3,257	6,011	4,758
4 April	8.50	3,799	2,691	11,626	8,235	9,442	6,688	13,793	9,770
5 May	7.50	3,430	2,144	3,419	2,137	9,442	5,901	13,793	8,621
6 June	6.50	4,882	2,645	4,867	2,636	9,442	5,114	13,793	7,471
7 July	5.50	2,979	1,366	2,970	1,361	7,583	3,476	11,078	5,077
8 August	4.50	3,190	1,196	3,180	1,192	7,583	2,844	11,078	4,154
9 September	3.50	4,391	1,281	4,377	1,277	7,583	2,212	11,078	3,231
10 October	2.50	4,496	937	4,481	934	7,952	1,657	11,617	2,420
11 November	1.50	38,830	4,854	38,706	4,838	7,952	994	11,617	1,452
12 December	0.50	46,518	1,938	16,087	670	7,952	331	11,617	484
13 **Total**		**135,029**	**38,580**	**134,598**	**59,209**	**87,275**	**40,017**	**127,494**	**58,459**
14 **Less Simple Average**			**67,514**		**67,299**		**43,638**		**63,747**
15 **Adjustment to Rate Base**			**(28,934)**		**(8,090)**		**(3,620)**		**(5,288)**

Table 5.6 above sets out the calculation of the forecast adjustments for capital expenditures for the period 2010 through 2013. In 2010, capital expenditures were heavily weighted to the last two months of the year, resulting in a reduction of the average Rate Base. During the 2011 to 2013 timeframe the expenditure pattern is forecast to be heavier in the second half of the year resulting in a negative Rate Base adjustment averaging $6 million.

2012 - 2013 Revenue Requirements Application
(2012-13 RRA)

Tab 6
2012-2013 Capital Expenditure Plan
(2012-13 Capital Plan)

June 30, 2011

FortisBC Inc.

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1. INTRODUCTION

The 2012 - 2013 Capital Expenditure Plan (2012-13 Capital Plan) of FortisBC Inc. (FortisBC or the Company) consists of expenditures of $105.86 million in 2012 and $129.08 million in 2013. The Company seeks Commission acceptance under section 44.2(3) of the Act that the 2012-13 Capital Plan is in the public interest as the capital expenditures requested are necessary for the Company to continue to provide reliable service, to ensure public and employee safety, and to deliver Demand Side Management (DSM) programs to the Company's growing customer base. In particular, the projects associated with these expenditures support British Columbia's energy objectives as defined in Section 2 of the *Clean Energy Act* and serve the interests of persons in British Columbia who receive or may receive service from FortisBC. The demand-side measures, for which expenditures (net of tax) of $5.8 million and $5.9 million for 2012 and 2013 respectively are sought, are cost-effective as prescribed by the *Demand Side Measures Regulation* enacted under the Act (the DSM Regulation).

In 2004, FortisBC prepared and filed its long-term 2005-2024 Transmission and Distribution System Development Plan (the 2005 SDP), which identified the need for reinforcements in the bulk transmission system, the regional transmission and distribution systems, and the telecommunications, protection, and SCADA (Supervisory Control and Data Acquisition) systems operated by the Company. The projects identified in the 2005 SDP were to be implemented over the subsequent six-year period, including a number of projects required to serve increasing loads largely driven by population growth in the FortisBC service area. With a few exceptions as identified in Updates to the SDP filed in 2005, 2006, and 2008, the major 2005 SDP projects planned during the medium term will have been completed by year-end 2011.

Concurrently with the 2012-13 Capital Plan, the Company has filed its 2012 Integrated System Plan (ISP), which includes the Company's 2012 Long Term Capital Plan. The 2012 Long Term Capital Plan outlines a 20 to 30 year horizon of planned investment spending on generation, transmission and distribution assets, and general plant including office facilities and Information Technology requirements, and provides the context in which the Company is seeking approval of the 2012-13 Capital Plan.

1.1 Summary of 2012-2013 Capital Expenditure Plan

FortisBC's 2012-13 Capital Plan is summarized in the following Table 1.1. The capital expenditures of $105.86 million in 2012 and $129.08 million in 2013 consist of

- Requested expenditures of $87.41 million in 2012 and a further $86.88 million in 2013;
- Previously approved expenditures of $7.92 million in 2012; and
- Estimated capital expenditures in the aggregate amounts of $10.52 million in 2012 and $42.13 in 2013 for which the Company expects to submit applications for CPCNs in 2012 and 2013 as identified in section 1.3 below.

The 2012 and 2013 expenditures, summarized in Table 1.1 below, are inclusive of the Cost of Removal (net of salvage recoveries). Further detail regarding the Cost of Removal for the projects contained in the 2012-13 Capital Plan is provided in Tab 7, Table 7A.

Table 1.1 - 2012-13 Capital Expenditure Plan

		2012	2013	2012	2013	2012	2013	2012	2013
		Requested		Previously Approved		CPCN Application		Total	
		($000s)							
1	Generation	4,495	2,947	5,636	-	-	-	10,131	2,947
2	Transmission and Stations	33,035	29,134	2,219	-	-	3,720	35,254	32,854
3	Distribution	29,249	25,889	-	-	-	-	29,249	25,889
4	Telecom SCADA Protection and Control	2,329	3,682	-	-	-	-	2,329	3,682
5	General Plant	12,503	19,317	69	75	10,521	38,408	23,093	57,800
6	**Subtotal Plant and Equipment**	**81,612**	**80,969**	**7,924**	**75**	**10,521**	**42,128**	**100,057**	**123,172**
7	Demand Side Management	5,798	5,909	-	-	-	-	5,798	5,909
8	**Total**	**87,410**	**86,878**	**7,924**	**75**	**10,521**	**42,128**	**105,855**	**129,081**

1.2 Legislative and Regulatory Framework

<u>Section 44.2 of the Act</u>

FortisBC files this 2012-13 Capital Plan pursuant to sections 44.2 (1) (a) and (b) of the Act, which provides that:

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

The Company seeks an order from the Company accepting the Company's 2012-2013 capital expenditures schedule is in the public interest under section 44.2(3) of the Act.

Pursuant to section 44.2 (5) of the Act, as amended by the *Clean Energy Act*, in reviewing the 2012-13 Capital Plan the Commission must consider:

(a) the applicable of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

For the purposes of the 2012-13 Capital Plan, the following are the applicable of British Columbia's energy objectives as defined in section 2 of the *Clean Energy Act*:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy…;

(c) to generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(g) to reduce BC greenhouse gas emissions…; and

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia.

In addition, the *Clean Energy Act* anticipates the implementation in British Columbia of smart metering and smart grid technology, and provides at section 17 (6) that

> *"if a public utility, other than the authority, makes an application under the Utilities Commission Act in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority"*.

The projects contained in the 2012-13 Capital Plan support British Columbia's energy objectives and, where appropriate, this support is identified in the relevant sections of the Application. The 2012-13 Capital Plan is also consistent with the Company's 2012 Long Term Resource Plan (Volume 2 of the ISP) filed pursuant to section 44.1 of the Act and concurrently with this Capital Expenditure Plan.

Section 6(4) of the *Clean Energy Act* provides:

> (4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for
>
> (a) the construction or extension of generation facilities, and
>
> (b) energy purchases,
>
> must consider British Columbia's energy objective to achieve electricity self-sufficiency.

As stated in the Company's Integrated System Plan, which is filed concurrently with this Plan, the Company has considered the British Columbia's energy objectives in planning its generation facilities to ensure they remain available for continued generation of clean and renewable power .

Section 19 of the *Clean Energy Act* relates to clean or renewable resources and is applicable to BC Hydro and to prescribed public utilities. FortisBC is not a prescribed public utility for the purpose of Section 19. However, the 2012-13 Capital Plan includes projects that support the use of clean and renewable sources, such as incenting the use of heat pumps through the Company's DSM program.

Accordingly, with the exception of the projects summarized in section 1.3 below and those previously approved, the Company seeks Commission approval of the projects listed in the following tables of the 2012 - 2013 Capital Expenditure Plan and the associated expenditures for the projects:

- Table 2.0 Generation;
- Table 3.0 Transmission;
- Table 4.0 Distribution;
- Table 5.0 Telecommunications, SCADA, and Protection and Control;
- Table 6.0 General Plant; and
- Table 7.0 Demand Side Management.

Section 45(6) of the Act

Section 45(6) of the Act provides that "A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct." The 2012-2013 Capital Expenditure Plan contains information on extensions that the Company intends to construct during the test period. The Company respectfully requests that the Commission finds the Plan satisfies section 45(6).

1.3 Certificates of Public Convenience and Necessity

Section 45(2) of the Act provides that a public utility (operating on September 11, 1980) is deemed to have received a CPCN authorizing the construction and operation of extensions to its system, unless the Commission determines that a separate CPCN application is required. Since 2005, FortisBC has filed applications for CPCNs for capital projects that meet the following conditions:

1. The total project cost is $20 million or greater; or
2. The project is likely to generate significant public concerns; or

3. FortisBC believes for any reason that a CPCN application should proceed; or
4. After presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application; or
5. The Commission determines that a CPCN application should proceed.

Consistent with these criteria, the Company intends to submit applications for CPCNs in 2012 and 2013 for the following projects:

- Kelowna Bulk Transformer Capacity Addition project, described in section 3.1.4, estimated at $25.6 million (exceeds the cost threshold);
- Advanced Metering Infrastructure (AMI) project, described in section 6.2, estimated at $38.5 million (exceeds the cost threshold); and
- Kootenay Long Term Facilities Strategy, described in section 6.1, estimated at $16.5 million (project planning falls between capital expenditure plan applications).

1.4 Expenditures by Plant Category

The following table provides a summary of the 2012-13 Capital Plan by major category.

Table 1.4 - Expenditures by Plant Category

		2012	2013	Total
1	**Generation**	**($000s)**		
2	Growth	-	-	-
3	Sustainment	10,131	2,947	13,079
4	Subtotal	10,131	2,947	13,079
5	**Transmission and Stations**			
6	Growth	11,832	8,847	20,679
7	Sustainment	23,423	24,007	47,430
8	Subtotal	35,254	32,854	68,108
9	**Distribution**			
10	Growth	13,646	13,759	27,406
11	Sustainment	15,603	12,130	27,733
12	Subtotal	29,249	25,889	55,138
13	**Telecom, SCADA, and Protection and Control**			
14	Growth	1,212	2,549	3,761
15	Sustainment	1,117	1,133	2,250
16	Subtotal	2,329	3,682	6,011
17	**General Plant**			
18	Kootenay Long Term Facilities Strategy	6,020	10,477	16,497
19	Trail Office Lease Purchase	-	10,000	10,000
20	Okanagan Long Term Solution	69	75	144
21	Central Warehousing	1,755	-	1,755
22	Advanced Metering Infrastructure	4,501	27,931	32,432
23	Information Systems	5,672	4,692	10,363
24	Vehicles	2,541	2,574	5,115
25	Metering Changes	403	406	809
26	Telecommunications	121	183	304
27	Buildings	1,362	883	2,245
28	Furniture and Fixtures	121	122	243
29	Tools and Equipment: Transmission-Distribution-Generation	528	457	985
30	Subtotal	23,093	57,800	80,893
31	Total Plant and Equipment	100,057	123,172	223,229
32	Demand Side Management (Net of Tax)	5,798	5,909	11,707
33	**Total**	**105,855**	**129,081**	**234,936**

2. GENERATION

FortisBC's generation facilities consist of 15 hydroelectric generating units in four plants located on the Kootenay River. These hydroelectric generating plants, initially constructed between 1897 and 1932, are renewed by both major projects which include the Upgrade and Life Extension (ULE) program that began in 1998 and additional capital sustainment projects, which are relatively small in scope and are necessary to maintain safe and efficient operation of the plants. These planned projects will ensure the continued long-term low-cost reliability of the generating units for customers' benefit.

By maintaining or increasing the capacity and energy of its hydroelectric generating facilities, the Company supports British Columbia's energy objectives as defined in the Clean Energy Act, in particular the objectives:

(a) to achieve electricity self-sufficiency; and

(c) to generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity.

Table 2.0 below summarizes the 2012 and 2013 expenditures for Generation projects for which FortisBC is seeking approval, or for which approval has already been granted.

Table 2.0 - Generation Projects

1	**Physical Infrastructure Projects** (approving orders)	**2012**	**2013**	**Total**
2			**($000s)**	
3	All Plants Concrete and Structural Rehabilitation	570	617	1,187
4	Upper Bonnington Spill Gate Rebuild (G-195-10)	1,085	-	1,085
5	Lower Bonnington Powerhouse Windows (G-195-10)	366	8	374
6	Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows	-	430	430
7	**Physical Infrastructure Projects Total**	**2,021**	**1,055**	**3,076**
8				
9	**Mechanical and Electrical Equipment Projects**			
10	Corra Linn Unit 2 Life Extension (C-5-09)	3,423	-	3,423
11	All Plants Station Service (G-147-06)	672	-	672
12	Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade (Revenue Meter Replacement) (G-195-10)	90	-	90
13	Corra Linn Unit 3 Completion	722	-	722
14	Upper Bonnington Old Plant Various Unit Upgrades	1,311	-	1,311
15	**Mechanical and Electrical Equipment Projects Total**	**6,218**	**-**	**6,218**
16				
17	**Dam, Public and Worker Safety Projects**			
18	Lower Bonnington, Upper Bonnington and Corra Linn Fire Panels	250	259	509
19	All Plants Safety and Security	471	475	946
20	**Dam, Public and Worker Safety Projects Total**	**721**	**734**	**1,455**
21				
22	**All Plants Minor Sustainment Projects**			
23	All Plants Minor Sustainment Capital	1,171	1,158	2,329
24	**All Plants Minor Sustainment Projects Total**	**1,171**	**1,158**	**2,329**
25				
26	**Total Generation Projects**	**10,131**	**2,947**	**13,078**

The focus of major capital investment at FortisBC Generation over the past dozen years has been the ULE program of 11 of the 15 generating units in the FortisBC system. The scope of a ULE project is a “water to wires” refurbishment of the generating unit, including refurbishment or replacement of trash racks, generators and turbines as well as improvements to auxiliary systems such as governor and excitation systems. The current schedule will see Corra Linn Unit 2 returned to service in the fourth quarter of 2011. Final completion of this project is scheduled for the first quarter of 2012 and will include the completion of a variety of smaller items required to substantially complete the project. As noted, this will complete eleven of the fifteen generating units at FortisBC’s four generating plants, with the potential for refurbishment of the remaining four old units at Upper Bonnington to be reviewed and addressed at a later date as further discussed in section 2.2.5.

In this Capital Expenditure Plan, Generation expenditures are classified in one of four broad categories, namely Physical Infrastructure, Mechanical and Electrical Systems, Dam, Public and Worker Safety and All Plants Minor Sustainment Capital.

Work planned for 2012 and 2013 includes the completion of projects previously approved by the Commission, as well as some minor investment in the old units at Upper Bonnington, completion of Corra Linn Unit 3 and the All Plants Safety and Security.

The Generation Projects contained in the 2012-2013 Capital Plan are described in the sections following.

2.1 Physical Infrastructure Projects

2.1.1 ALL PLANTS CONCRETE AND STRUCTURAL REHABILITATION

This project involves expenditures for completing multiple concrete and structural steel rehabilitation jobs necessary to sustain the existing physical infrastructure at the generating facilities. The FortisBC generating facilities range from 70 to100 years old, and have experienced deterioration as can be expected of facilities of this vintage.

A combination of engineering inspections and reports of all generating facilities has identified a number of locations where concrete deterioration has occurred and structural steel deficiencies exist. Some of the identified deficiencies require resurfacing of deteriorated concrete and repair of waterway structures including spillway piers, forebay piers, forebay walls, spillway walls and tailrace piers.

If left unchecked, this deterioration can create employee safety hazards and potential risks to the structural integrity of the dams. In addition, if not addressed proactively, the deterioration will continue to accelerate over time through exposure to weather conditions, resulting in increased expenditures in future years to address the issues.

FortisBC defines the “All Plants Concrete and Structural Rehabilitation” project as a group of projects from all four FortisBC generating facilities completed as an eighteen year program.

A current list of jobs will be compiled each budget year based on a priority rating system. The ranking system used to prioritize concrete and structural steel rehabilitation projects ensures a sustainable level of investment in the facilities such that large scale rehabilitation projects are avoided in future years. It also ensures that any safety or performance issues are addressed in a timely manner by assessing projects based on Service Risks and Public (or worker safety) Risks.

Options considered and rejected were;

- Do nothing or delay project start option was considered and rejected because concrete has begun to deteriorate. Left unaddressed, concrete deterioration will proceed at an exponential rate due to increased surface area for moisture ingress and concrete spalling as a result of freeze-thaw cycles. Sufficient deterioration can potentially impact structural integreity and lead to high cost repairs in future years. Structural steel is included in this category due to a number of assessments that have been completed, and deficiencies identified; and
- The option of presenting individual concrete and structural rehabilitation projects was reviewed and rejected due to efficiency gains realized by grouping smaller projects into one project.

The All Plants Concrete and Structural Steel Rehabilitation program will provide sustaining levels of investment in the facilities, but does not include major rehabilitation projects which are required over the next 20 years. Project costs are estimated at $0.57 million in 2012 and $0.62 million in 2013.

2.1.2 UPPER BONNINGTON SPILL GATE REBUILD

This project was approved by Commission Order G-195-10. The scope of work for 2011 involves modifications to the existing structure to provide a means of isolating the existing spill gates for refurbishment and ongoing future maintenance. With the completion of the required work in 2011 to isolate the gates, work scheduled for 2012 involves the refurbishment of the existing gates.

The project costs are estimated at $1.09 million in 2012. This project is currently on scope, schedule and budget.

2.1.3 LOWER BONNINGTON POWERHOUSE WINDOWS

This project was approved by Commission Order G-195-10 and involves replacing the power house windows at the Lower Bonnington plant in 2011 and 2012. The project costs are estimated to be $0.37 million in 2012 and $0.01 million in 2013. This project is currently on scope, schedule and budget.

2.1.4 UPPER BONNINGTON, SOUTH SLOCAN AND CORRA LINN POWERHOUSE WINDOWS

Windows in the powerhouses at all four of FortisBC's generating plants are manually operated on a routine basis to regulate the temperature within the powerhouse. Although these powerhouses use an airwash system during summer months to facilitate plant cooling, the windows of these facilities play a key role in regulating the plant temperature during the spring and fall seasons. Depending on the facility, the windows range in vintage from 70 to 100 years old. Due to deterioration of component parts, many windows are at risk of falling out. The resulting safety risk to plant personnel is most notable during regular manual operation of the windows.

FortisBC has engaged an engineering consultant to provide an independent assessment of the windows in the Upper Bonnington, South Slocan and Corra Linn facilities. Windows identified to be at risk of failure at these facilities have been scheduled for replacement or refurbishment within this project.

Options considered and rejected were;

- The do nothing option was considered at all plants and rejected because of the age and structural condition of some of the windows;
- Delay of project implementation option was considered and rejected due to the risk of failure. The windows are part of the plant cooling system and are required to be operable throughout the year. Delaying this project creates a risk to the safety of plant personnel; and
- The option of a complete replacement or refurbishment of all the windows was considered and rejected because not all the windows are at risk of failure.

Directly related projects are Lower Bonnington Power House Windows (2011/2012 approved by Commission Order G-195-10) and remaining Power House Window Replacement (2017 or later).

The project costs are estimated to be $0.43 million in 2013.

2.2 Mechanical and Electrical Equipment Projects

2.2.1 CORRA LINN UNIT 2 LIFE EXTENSION

The Corra Linn Unit 2 Life Extension was approved by Commission Order C-5-09. The generating unit will be returned into service in December 2011, with completion of final project tasks including final efficiency testing of the turbine in the second quarter of 2012. The project will be fully closed out in the fourth quarter of 2012 after final inspection of the turbine.

The project costs are estimated to be $3.42 million in 2012. This project is currently on scope, schedule and budget.

2.2.2 ALL PLANTS STATION SERVICE

This project was approved by Commission Order G-147-06 and involves the installation of new equipment and back-up power sources to ensure operational reliability and to address environmental concerns at all four FortisBC generating plants. South Slocan was completed in 2009 and Corra Linn was substantially completed in 2010. Lower Bonnington is scheduled for completion in 2011 and Upper Bonnington will be substantially completed in 2012.

The project costs are estimated to be $0.67 million in 2012. This project is currently on scope, schedule and budget.

2.2.3 LOWER BONNINGTON AND UPPER BONNINGTON PLANT TOTALIZER UPGRADE (REVENUE METER REPLACEMENT)

This project was approved by Commission Order G-195-10 and involves replacing seven existing PSI Quad 4 meters with five new PML-7650 meters. This is a two-year project that began in 2011 and will be completed in 2012. The project costs are estimated to be $0.09 million in 2012. This project is currently on scope, schedule and budget.

2.2.4 CORRA LINN UNIT 3 COMPLETION

The proposed work for this project includes installing new trash racks, upgrading the transformer bay oil spill containment, and the procurement of spare generator coils.

The trash racks are original equipment and are over 80 years old. Deterioration due to corrosion of the submerged uncoated steel and numerous weld repairs over the years, making the structure more brittle, are the primary drivers for replacement. Work completed on Corra Linn Unit 1 indicated that the trash racks on that unit were in very poor condition and were replaced as part of the ULE project for that unit. The risk of deferring this work is a trash rack failure which could result in structural steel components or logs entering the scroll case and damaging the wicket gates or turbine.

Transformer bay oil containment upgrades are required to bring the oil containment for the Unit 3 transformer up to current FortisBC standard. The existing containment is known to leak and in the event of a transformer failure there is a high risk of oil entering the river. The proposed containment will be built to match the containment installed as part of the ULE program for Unit 1 and Unit 2 transformers.

Spare generator coils specific to Unit 3 are required based on reliability. Several coils installed during the ULE did not pass quality control standards but remained in the unit due to the high cost to repair. Although testing of coils indicates they are not at risk of immediate failure, any failure of the coils would require an outage of approximately two months to procure and install replacement coils at an approximate outage cost of $0.7 million.

Options considered and rejected were:

- Do nothing or delay project start option was considered and rejected due to reliability and environmental reasons; and
- The option of spreading this project over multiple years was considered and rejected due to the cost benefits of completing the work under one outage.

The total project costs including new trash racks, installation of oil containment and purchase of spare generator coils are estimated to be $0.72 million in 2012.

2.2.5 UPPER BONNINGTON OLD PLANT VARIOUS UNIT UPGRADES

The Upper Bonnington Generating facility includes the "Old Plant", originally constructed in 1907 with four generating units averaging 5.8 megawatts (MW) in size. An addition to the facility in 1940 provided two additional generating units approximately 18 MW in size which were upgraded through the Upgrade and Life Extension program in 2004.

Under the Canal Plant Agreement, FortisBC gives control of 12,800 cubic feet per second (cfs) of licensed water to BC Hydro, and in return, BC Hydro supplies an entitlement of 470.2 GWh (and 62 MW) to FortisBC. In order to receive this entitlement, FortisBC is obligated to keep the units in operating order. If the four old generating units were to fail, the entitlement energy would be reduced. The terms of the Canal Plant Agreement dictate that FortisBC's entitlement would be reduced by 126 GWh and 22 MW (Entitlement Loss) if the four old generating units were to fail. The cost of this entitlement loss is estimated at approximately $4 million per year.

Since many of the major components of the Upper Bonnington generating units 1 - 4 are approaching 100 years in age, investment in sustainment capital projects is required to ensure the ongoing safe operation of this facility with reasonable reliability. The need to upgrade these units has been assessed on the basis of risk of failure and overall benefit to customers, including the potential rate impact as a result of undertaking the upgrade. The assessment demonstrated the need to maintain this generation resource for the benefit of FortisBC customers, but also indicated that since the units are still operating satisfactorily, the project is not required at this time. Recognizing the age of the equipment, the Company expects that normal operation of this equipment could require higher maintenance costs over time, and also recognizes that the reliability of this plant cannot match that of the plants which have been addressed under the Upgrade Life Extension program. In order to ensure the continued safe operation of these units, the Company is proposing a scope of work in 2012/2013 to address some operational and safety concerns. The scope of work includes sustainment capital work on headgate seals, generators, turbines, governors and unit transformers. For example, the headgate seals require new sealing timbers. The generator, turbine and governor require replacement and rehabilitation of some mechanical components such as links, pins, bushings and brake system refurbishment.

The unit transformers require development of a connection point for a mobile substation to minimize outage times in the event of a transformer failure.

This capital investment is necessary to permit FortisBC to continue to operate these generating units as they have been in the past. The Company will continually assess the ability of these generating units to provide reliable service, and will present an application to the Commission to rebuild the generating units when it is apparent that they can no longer be operated without significant capital investments or an increasing operating and maintenance costs.

Options considered and rejected were;

- The do nothing or delay project start option was rejected since the generating units are over 100 years old and are at risk of failure. By completing relatively low cost sustainment upgrades, the generating units can be kept in good operating order until the time that the generating units are rebuilt; and

The option of an Upper Bonnington Old Unit Repowering project which included the rehabilitation of the old units (a generator rewind, transformer replacement and exciter replacement) and the installation of new runners was considered, however as the condition of the equipment still permits satisfactory and reliable operation, consideration of this option has been deferred. The equipment condition will be continually re-evaluated to determine when rehabilitation of Units 1 - 4 at Upper Bonnington consistent with the scope of past ULE projects is warranted.Directly related projects are the Upper Bonnington Old Unit Repowering project (2017 or later), described in section 2.4.4 of the 2012 Long Term Capital Plan.

The Upper Bonnington Old Plant Various Unit Upgrades project costs are estimated at $1.31 million in 2012.

2.3 Dam, Public, and Worker Safety Projects

2.3.1 UPPER BONNINGTON, LOWER BONNINGTON AND CORRA LINN FIRE PANELS

This project involves the installation of fire alarm panels at the Lower Bonnington, Upper Bonnington, and Corra Linn generating stations. Presently there is no alarm system in the plants except for the water deluge system for the generating units. The proposed fire alarm panels will be multi zone and will include fire pull stations, audible and visual alarms, and fire and smoke detectors. These alarm panels are for employee safety only. These panels will not include controls nor will it be linked to a suppression system. The fire panel will annunciate to a central monitoring location. This is a three year project from 2012 - 2014 with a total project cost of $0.77 million.

Options considered and rejected were;

- A do nothing or delay project start option was considered and rejected. Recent consultant reports recommended fire safety upgrades, particularly where there are personnel safety concerns;
- A combined fire panel and personnel egress project was considered and rejected. The All Plants Fire Safety project was initiated as a separate project to minimize rate impact;

- A plant fire suppression system option was considered and rejected. The option to extend the fire suppression system to include the rest of the plant was cost prohibitive; and
- Equipment isolation system in case of a fire was considered and rejected due to the complexity involved in isolating all electrical power sources.

Directly related projects are the South Slocan Fire Panels (2011 - approved by Commission Order G-195-10) and All Plants Fire Safety (2014-2017), which is described in section 2.5.3.3 of the 2012 Long Term Capital Plan.

The project costs are estimated at $0.25 million in 2012 and $0.26 in 2013 ($0.25 million in 2014).

2.3.2 ALL PLANTS SAFETY AND SECURITY

This project involves an upgrade of safety and security at all four FortisBC generating plants, accomplished through increasing the level of hazard awareness and restricting access to dangerous or controlled areas to mitigate risk. An incident likelihood rating was completed and areas of concern are from 7 kilometres upstream of the Corra Linn Dam to 1.3 kilometres downstream of the South Slocan Dam (a total distance of 13.3 kilometres). Within this zone are four private railway crossings and areas where FortisBC owns property or has a presence in connection with the ownership and/or maintenance of its Kootenay River plants. This upgrade will include the installation of signs, concrete road barriers and additional perimeter fencing. This work is required to minimize the liability associated with any public incident related to the facilities, maintain public safety and security in accordance with good utility practice and remain consistent with recommendations set out and developed by the Canadian Dam Safety Association. Expenditures on this project are expected to be spread out over a four year time frame beginning in 2012 with a total expenditure over the four years of approximately $1.81 million.

Options considered and rejected were:

- Do nothing or delay project start option was considered and rejected due to the risk of liability and public safety;
- The option of completing the All Plants Safety and Security project in conjunction with the All Plants Surveillance and Security project was considered and rejected based on customer rate impact; and

- Installing this entire project during a one to two year period option was considered and rejected, primarily for reasons of rate mitigation.

Directly related projects are All Plants Surveillance and Security (2017 or later) which is described in section 2.5.3.4 of the 2012 Long Term Capital Plan.The costs for the All Plants Safety and Security project are estimated at $0.47 million in 2012 and $0.48 million in 2013.

2.4 All Plants Minor Sustainment Projects

2.4.1 ALL PLANTS MINOR SUSTAINMENT CAPITAL

This project involves expenditures for completing a number of minor repair jobs that have been identified at the generating plants as a result of safety inspections, storm damage, aging equipment, reports by on-call personnel and other inspections.

FortisBC defines the “All Plants Minor Sustainment Capital” project at Generation as a collection of small jobs with individual estimate levels less than $0.5 million in value. A list of projects is formed prior to every budget year based on a priority rating system. The All Plants Minor Sustainment Capital category includes the following projects.

2.4.1.1 All Plants Lighting Upgrades (2012 and 2013)

This project involves upgrades to the existing lighting system including adding new lights to increase illumination levels to WorkSafeBC standards, new controls, and removal of old fixtures and controls. The Upper Bonnington tailrace and forebay areas are scheduled to be upgraded in 2012, with the South Slocan tailrace and airwash area and the Corra Linn tailrace area scheduled to be upgraded in 2013.

2.4.1.2 All Plants Embedded Piping (2012 and 2013)

This is a multi-year project that involves the inspection, pipe replacement, and valve refurbishment of the embedded dewatering pipes at Lower Bonnington, Upper Bonnington, South Slocan and Corra Linn. The embedded piping systems have been in service for over 70 years. Corrosion of these components is causing dewatering system failures. In 2008 while dewatering Unit 3 at the Corra Linn plant for an annual inspection, a 24 inch pipe failed due to corrosion. Fortunately, the location of the pipe in this instance allowed for an easy repair which only resulted in a delay to the start of the inspection, and no increase in the unit outage required. Failure of the pipe in another location or for an emergency unit repair could result in a longer outage and increased repair costs.

2.4.1.3 Corra Linn Upgrade Headgate Hoist (2012)

Operation of the headgate hoist is necessary to ensure reliable operation of the generating units. This project involves rebuilding the motors and refurbishing the gear reducers to extend the life of the remaining three (of six) headgate hoists at Corra Linn. The refurbishment of the first three headgate hoists was completed in 2008.

From a reliability perspective, the three remaining hoists have not received an overhaul in thirty years. From an environmental perspective, the existing gear reducers do not have seals around the output shafts. This can result in grease and gear oil entering the river which is not permitted under existing regulations. This project will extend the life of the remaining three headgate hoists and address these environmental and reliability issues.

2.4.1.4 All Plants Telephone Communications (2012 and 2013)

This is a multi-year project involving the installation of new cables and handsets at Lower Bonnington, Upper Bonnington, South Slocan and Corra Linn. Reliable communication at the plants is critical for safety and reliability issues.

2.4.1.5 Corra Linn Spillway Gantry 2 Gate Height Indication (2012)

Gate height indicators produce a signal to the System Control Center to provide an accurate measurement of spill gate height which is required for proper control of forebay and tailrace water levels. This project involves replacing the old, unreliable mechanical height indicator with a newer, reliable electronic height indicator.

2.4.1.6 All Plants Davit Arm (2012)

This project involves constructing a Davit Arm (lifting device) and multiple mounting base plates. The base plates will be permanently installed at the required locations at the Lower Bonnington, Upper Bonnington, South Slocan and Corra Linn facilities to permit moving of items such as oil drums in restricted access locations. This project will improve worker safety by mitigating the need for manual lifting in difficult access locations.

2.4.1.7 All Plants Air System Upgrade (2012 and 2013)

This is a multi-year project that involves replacing the brake and service air components that have reached the end of their reliable life. The air system has been in service more than 70 years. Corroded components need to be replaced and the addition of air dryers will reduce future corrosion. One plant per year will be completed.

2.4.1.8 Lower Bonnington and Upper Bonnington Upgrade Spillway Gate Control Phase 2 (2012 and 2013)

This is a multi-year project that involves replacing the old control system and power wiring with new equipment. The existing controls contain asbestos and do not meet current electrical code standards. Failure of the spillway gate controls would result in the inability to open the gates, which could potentially result in water over topping the dam and causing damage to the powerhouse.

2.4.1.9 Corra Linn Airwash Intake Screen Upgrades (2012)

This project involves replacing the old wood frame screens with new aluminum frame screens. The old wood frame screens require rebuilding every 15 years due to rot and deterioration. The installation of aluminum screens would provide a long life option resistant to the effects of rot and deterioration at the location of this installation.

2.4.1.10 Upper Bonnington Spillway Gate Hoist Upgrade (2013)

This project involves rebuilding the drive motors, gear boxes including seals, and replacement of equipment such as the wire rope. The existing gear boxes do not include seals in locations to ensure that grease and gear oil do not enter the river, and as a result pose an environmental risk with a possibility of grease entering the river. This project will extend the life of the two spillway gate hoists and address environmental and reliability issues.

2.4.1.11 Lower Bonnington, Upper Bonnington, Corra Linn Old Wiring Removal (2012 and 2013)

This project involves removal of all old electrical equipment and wiring no longer in service at Lower Bonnington, Upper Bonnington and Corra Linn generating plants. The wiring presents a health and safety concern as it contains asbestos and lead sheaths.

These projects combined are estimated at $1.17 million in 2012 and $1.16 million in 2013 as shown in Table 2.4.1 below.

Table 2.4.1 - All Plants Minor Sustainment Capital Projects

1		**2012**	**2013**	**Total**
2			**($000s)**	
3	All Plants Lighting Upgrades	156	204	360
4	All Plants Embedded Piping	321	323	643
5	Corra Linn Upgrade Headgate Hoist	156	-	156
6	All Plants Upgrade Telephone Communications	26	53	79
7	Corra Linn Spillway Gantry 2 Gate Height Indication	26	-	26
	All Plants Davit Arm	39	-	39
9	All Plants Air System Upgrade	214	215	429
10	Lower Bonnington and Upper Bonnington Upgrade Spillway Gate Control Ph. 2	75	168	243
11	Corra Linn Airwash Intake Screen Upgrades	70	-	70
12	Upper Bonnington Spillway Gate Hoist Upgrade	-	105	105
13	Lower Bonnington, Upper Bonnington, Corra Linn Old Wiring Removal	88	90	178
14	**All Plants Minor Sustaining Capital**	**1,172**	**1,158**	**2,330**

3. TRANSMISSION AND STATIONS

The 2012-13 capital expenditure plan for Transmission and Stations follows the direction of the 2005 SDP, subsequent updates, and the 20 year Integrated System Plan (ISP). A significant difference between the SDP plan established in 2005 and the new ISP is the Company's need to shift focus from growth to sustainment requirements. The Company is still forecasting continual growth in all regions of the service territory, but the growth rate has decreased. Growth projects will still occur throughout the service territory, but they will require less investment as the projects will likely be completed on brownfield (existing) facilities as opposed to greenfield (new) sites.

The completion of these transmission and station projects supports British Columbia's energy objectives as defined in the *Clean Energy Act*, in particular the objective:

> (c) to generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity.

The projects also support the Policy Actions outlined in the Energy Plan, in particular Policy Action:

> (12) … to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.

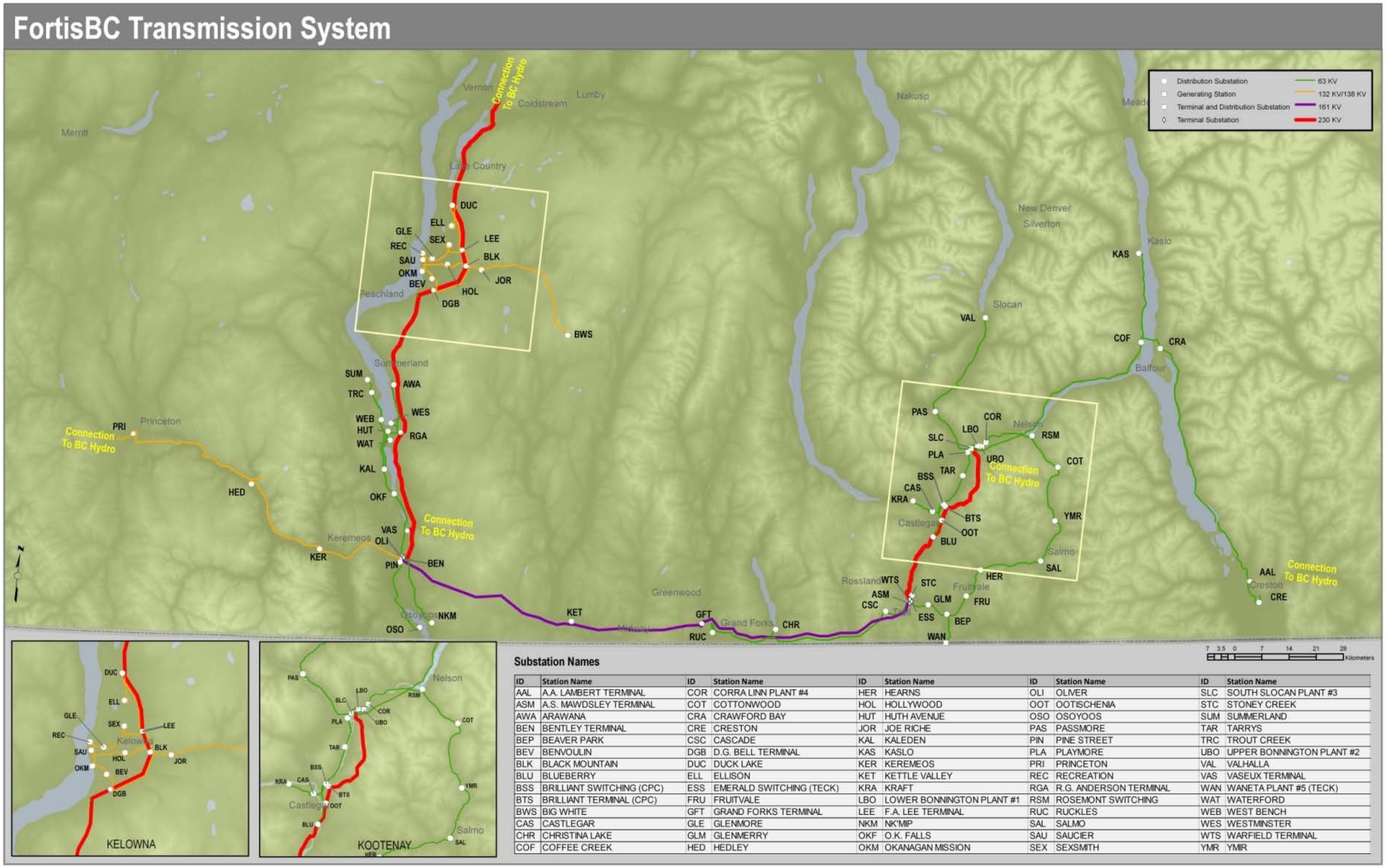
Table 3.0 below summarizes the 2012 and 2013 expenditures for Transmission and Stations projects for which FortisBC is seeking approval, or for which approval has already been granted. The only exception is the Kelowna Bulk Transformer Capacity Addition project for which FortisBC is not seeking approval through the 2012-13 Capital Plan submission. FortisBC intends to submit an application for a CPCN for this project in early 2012.

Table 3.0 - Transmission and Stations Projects

1		2012	2013	Total
2	**Transmission Growth** (approving Orders)		($000s)	
3	Okanagan Transmission Reinforcement (C-5-08)	2,219	-	2,219
4	Ellison to Sexsmith Transmission Tie	7,122	413	7,535
5	Grand Forks Transformer Addition /High Capacity Communications	2,491	4,714	7,205
6	Kelowna Bulk Transformer Capacity Addition	-	3,720	3,720
7	**Total Transmission Growth**	**11,832**	**8,847**	**20,679**
8				
9	**Transmission and Station Sustainment Projects**			
10	**Transmission Sustainment**			
11	Transmission Line Condition Assessment	522	485	1,007
12	Transmission Line Rehabilitation	3,372	2,621	5,993
13	Transmission Line Urgent Repairs	594	620	1,214
14	Transmission Line Right-of-Way Easements	400	400	800
15	6 Line /26 Line River Crossing Reconfiguration	1,185	-	1,185
16	27 Line Rebuild (Corra Linn-Salmo)	1,161	-	1,161
17	21-24 Lines Rebuild (Generation Plants)	2,219	-	2,219
18	19 Line/29 Line Reconfiguration	-	791	791
19	20 Line Rebuild (Warfield Terminal-Salmo)	-	4,664	4,664
20	**Total Transmission Sustainment**	**9,453**	**9,581**	**19,034**
21				
22	**Station Sustainment**			
23	Environmental Compliance (PCB Mitigation)	11,269	11,553	22,822
24	Station Urgent Repairs	818	907	1,725
25	Station Assessment/Minor Planned Projects	1,343	1,354	2,697
26	Add Arc Flash Detection to Legacy Metal-Clad Switchgear	539	544	1,083
27	Huth Low Voltage Breaker Replacement	-	69	69
28	**Total Station Sustainment**	**13,969**	**14,427**	**28,396**
29	**Total Transmission and Stations Sustainment**	**23,423**	**24,007**	**47,430**

Figure 3.0 below details FortisBC's transmission network, including the associated terminal and distribution substations.

Figure 3.0 - FortisBCTransmission Network



Substation Names

ID	Station Name	ID	Station Name	ID	Station Name	ID	Station Name	ID	Station Name
AAL	A.A. LAMBERT TERMINAL	COR	CORRA LINN PLANT #4	HER	HEARNS	OLI	OLIVER	SLC	SOUTH SLOCAN PLANT #3
ASM	A.S. MAWDSLEY TERMINAL	COT	COTTONWOOD	HOL	HOLLYWOOD	OOT	OOTISCHENIA	STC	STONEY CREEK
AWA	ARAWANA	CRA	CRAWFORD BAY	HUT	HUTH AVENUE	OSO	OSOYOOS	SUM	SUMMERLAND
BEN	BENTLEY TERMINAL	CRE	CRESTON	JOR	JOE RICHE	PAS	PASSMORE	TAR	TARRYS
BEP	BEAVER PARK	CSC	CASCADE	KAL	KALEDEN	PIN	PINE STREET	TRC	TROUT CREEK
BEV	BENVOULIN	DGB	D.G. BELL TERMINAL	KAS	KASLO	PLA	PLAYMORE	UBO	UPPER BONNINGTON PLANT #2
BLK	BLACK MOUNTAIN	DUC	DUCK LAKE	KER	KEREMEOS	PRI	PRINCETON	VAL	VALHALLA
BLU	BLUEBERRY	ELL	ELLISON	KET	KETTLE VALLEY	REC	RECREATION	VAS	VASEUX TERMINAL
BSS	BRILLIANT SWITCHING (CPC)	ESS	EMERALD SWITCHING (TECK)	KRA	KRAFT	RGA	R.G. ANDERSON TERMINAL	WAN	WANETA PLANT #5 (TECK)
BTS	BRILLIANT TERMINAL (CPC)	FRU	FRUITVALE	LBO	LOWER BONNINGTON PLANT #1	RSM	ROSEMONT SWITCHING	WAT	WATERFORD
BWS	BIG WHITE	GFT	GRAND FORKS TERMINAL	LEE	F.A. LEE TERMINAL	RUC	RUCKLES	WEB	WEST BENCH
CAS	CASTLEGAR	GLE	GLENMORE	NKM	NK'MIP	SAL	SALMO	WES	WESTMINSTER
CHR	CHRISTINA LAKE	GLM	GLENMERRY	OKF	O.K. FALLS	SAU	SAUCIER	WTS	WARFIELD TERMINAL
COF	COFFEE CREEK	HED	HEDLEY	OKM	OKANAGAN MISSION	SEX	SEXSMITH	YMR	YMIR

3.1 Transmission and Station Growth Projects

Table 3.1 - Transmission Growth Projects

1		2012	2013	Total
2	**Transmission Growth** (approving Orders)		**($000s)**	
3	Okanagan Transmission Reinforcement (C-5-08)	2,219	-	2,219
4	Ellison to Sexsmith Transmission Tie	7,122	413	7,535
5	Grand Forks Transformer Addition	2,491	4,714	7,205
6	Kelowna Bulk Transformer Capacity Addition	-	3,720	3,720
7	**Total Transmission Growth**	**11,832**	**8,847**	**20,679**

3.1.1 Okanagan Transmission Reinforcement (OTR) Project

The OTR Project was approved by Commission Order C-5-08. As part of the OTR Project, BC Hydro is required to install a new 500 kV circuit breaker on the BC Hydro 500 kV side of the station with associated protection and control changes to allow independent switching of the FortisBC 230 kV transformers. BC Hydro has submitted its project plan for this required work, with the scheduled in-service date delayed from the fall of 2011 to summer 2012. This delay resulted from extended discussion and negotiations with respect to BC Hydro cost estimates and management. FortisBC signed off the facilities agreement at the end of February 2011 to secure the in-service date. This component of work has no material impacts on the completion of FortisBC's new and upgraded facilities.

The BC Hydro Vaseux Terminal 500 kV work will be completed in 2012 with expenditures of $2.2 million in 2012. This delay has not resulted in any total project increases. The OTR Project is forecast to be under budget.

3.1.2 Ellison to Sexsmith Transmission Tie

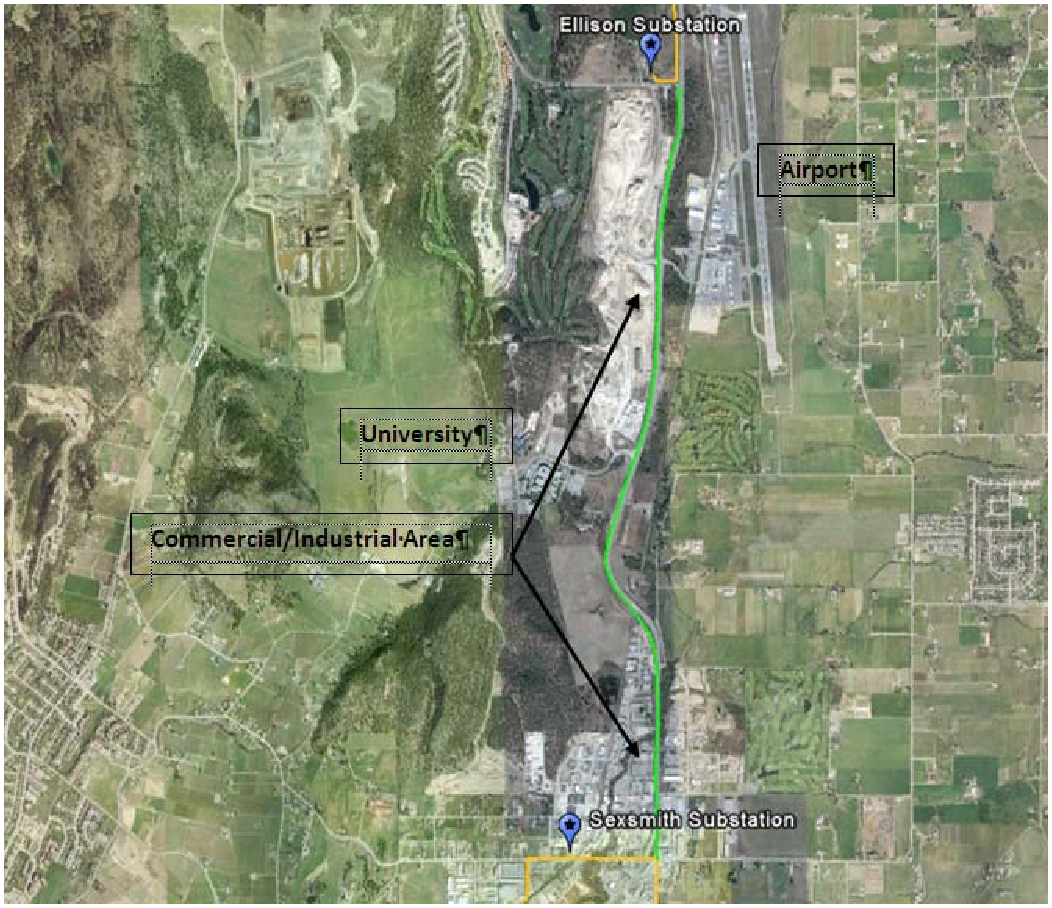
The Ellison and Duck Lake substations are currently fed radially from FA Lee Terminal station via 46 Line as shown in Figure 3.1.2 (b) below. With this configuration, a fault on 46 Line will result in an outage to both stations. With a single transmission line supplying the area, it is not possible to completely restore supply until that transmission line is repaired. There is minimal distribution backup into this area since the adjacent Sexsmith distribution source is already heavily loaded and a distance of five kilometres or more from the majority of the load concentration served by the Ellison and Duck Lake stations. The Ellison and Duck Lake stations serve approximately 75 MVA of load including a number of large customers such as the University of British Columbia Okanagan, Kelowna International Airport and Kelowna Flightcraft.

The need for the Ellison to Sexsmith tie was identified in the application for a CPCN for the Ellison Substation, approved by Commission Order C-4-07, and at that time was anticipated to be constructed in 2010. In the 2009 SDP Update, the Company rescheduled the transmission loop for the Sexsmith, Ellison and Duck Lake substations to the 2011 or later timeframe. With the addition of new distribution load (BC Hydro customers in the Winfield area) onto the Duck Lake Substation in 2010, a transmission outage on 46 Line will affect approximately 9,700 customers served by this line. During the negotiations with BC Hydro (then BCTC) for the Duck Lake Wheeling Agreement, it was understood that two sources of supply were being planned for the Duck Lake substation by 2012 (as documented in the Duck Lake Wheeling Agreement Application approved by Commission Order G-19-10), consistent with the 2009 SDP Update.

This project involves adding a 138 kV line termination and all associated bus work at the Ellison Substation and the construction of a 138 kV line from the Ellison Substation to a tap into 50 Line near the Sexsmith Substation.

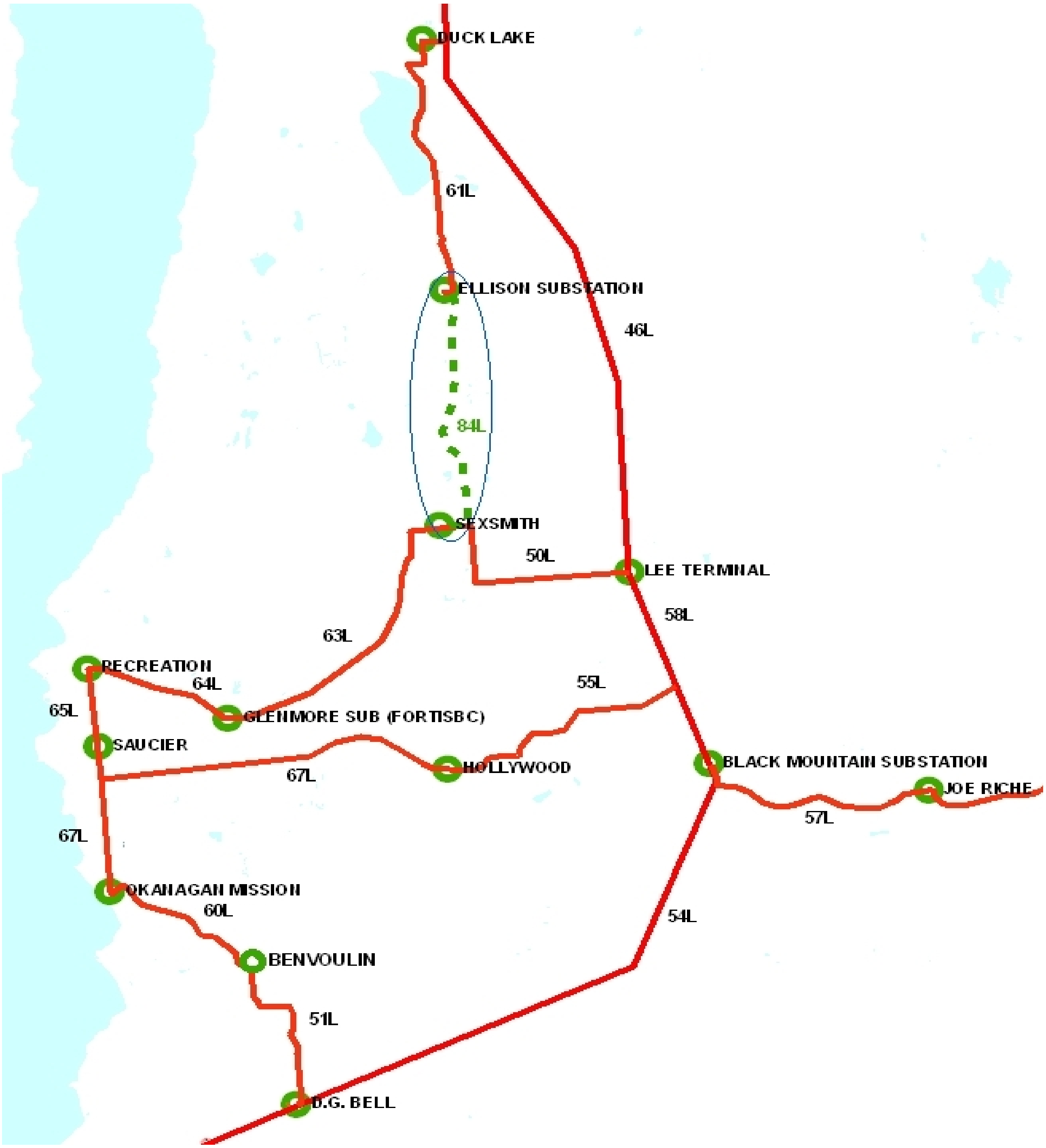
The satellite imagery in Figure 3.1 (a) below shows the area where the Ellison to Sexsmith transmission tie is proposed along with the highway corridor it will follow. On the north side (top) it will pass by the airport on the west side of the highway near an industrial/commercial business park and continue south past the university area. There is some commercial development on the south end of the line right of way where it is proposed the transmission tie will connect with the existing 50 Line. The transmission circuit will be overbuilt on an existing 13 kV distribution line that runs the full length of the proposed line route.

Figure 3.1 (a) - Satellite view of Ellison to Sexsmith Transmission Tie



The construction of this line segment will provide a 138 kV loop in the northern portion of Kelowna, complementing the two existing 138 kV transmission loops, thus providing N-1 transmission reliability for all areas of Kelowna. Figure 3.1 (b) below shows the Kelowna area system with the proposed Ellison to Sexsmith Transmission Tie.

1
Figure 3.1 (b) - 50 Line Overview



2

This project will also provide the option of taking 46 Line out of service for maintenance thereby eliminating the need for more complex and costly live-line procedures or taking outages on both the Duck Lake and Ellison Stations when conducting maintenance work on 46 Line.

The engineering costs for this project were approved by Commission Order G-195-10. The project budget was derived from engineered planning estimates adjusted for inflation and changes in overhead loadings. Including the engineering costs for the project as previously approved by Order G-195-10, the Ellison to Sexsmith Transmission Tie project is estimated to cost $8.2 million with expenditures of $0.69 million in 2011, $7.1 million in 2012 and $0.41 million in 2013.

3.1.3 GRAND FORKS TERMINAL TRANSFORMER ADDITION AND HIGH-CAPACITY COMMUNICATIONS PROJECT

Introduction and Project Summary

The Grand Forks Terminal Transformer Addition and High-Capacity Communications project is intended to address two FortisBC system deficiencies:

1. Transmission system reliability issues for the Grand Forks area; and
2. A gap between the Okanagan and Kootenay communications systems.

There is a significant cost-saving opportunity to the benefit of FortisBC customers if the projects are considered in conjunction, rather than addressed individually and in isolation.

The full project is proposed to be constructed over four years. In 2012/13, a spare transmission transformer will be relocated and stored at the Grand Forks Terminal and a high-capacity communications fibre optic link between Grand Forks and Warfield will be constructed. In 2014/15, the transformer would be installed at the Grand Forks Terminal and aging 63 kV transmission lines between Rossland and Christina Lake would then be salvaged.

Presently, FortisBC is only seeking approval for expenditures related to the relocation and storage of the transformer at the Grand Forks Terminal and for the construction of the fibre optic link between Grand Forks and Warfield. Approval for expenditures related to the installation of the transformer (and construction of associated substation works) as well as the salvage costs for the 63 kV transmission lines will be the subject of a future Capital Expenditure Plan application (currently proposed for 2014/15).

The following sections discuss the two system deficiencies in detail. An options analysis leading to the proposed project solution is then presented.

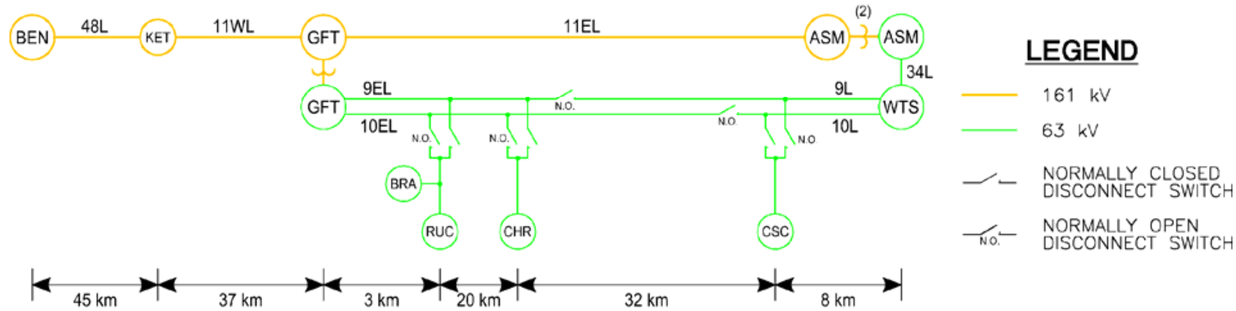
Grand Forks Area Transmission Limitations

The Grand Forks Terminal is a major substation which provides the normal transmission supply for Grand Forks, Christina Lake and surrounding areas. The station is supplied at 161 kV both from Warfield (via the A.S. Mawdsley Terminal) and from Oliver (via the Bentley Terminal) and thus has full single-contingency (N-1) reliability from a 161 kV bulk supply perspective. The 161 kV voltage is stepped down to 63 kV via a single 161/63 kV transformer referred to as Grand Forks Terminal T1 transformer. This transformer, which was manufactured in 1965 (i.e. 46 years old), provides a 63 kV transmission supply to the:

- Grand Forks Terminal T3 distribution transformer;
- Ruckles Substation;
- Roxul Substation (a wholesale transmission customer); and
- Christina Lake Substation.

As there is only one 161/63 kV transformer installed at the Grand Forks Terminal, a backup 63 kV source is provided via two 63 kV transmission lines which originate at the Warfield Terminal Station near Trail. This backup source is only used in the event that that T1 transformer is unavailable. Protection and communications limitations prevent the Grand Forks and Trail 63 kV systems from operating in parallel. As a consequence, the Grand Forks Terminal T1 transformer provides only a radial 63 kV supply to the area. If the transformer experiences a forced outage, then customers in the area will be without power until the system can be manually reconfigured to use the backup 63 kV supply from Trail. Figure 3.1.3 (a) below shows the current transmission configuration in the Grand Forks area.

Figure 3.1.3 (a) - Existing (2011) Boundary / Grand Forks Area Transmission System



In the normal operating configuration the Grand Forks Terminal T1 transformer supplies approximately 3,500 direct FortisBC customers. The Ruckles Substation is also a distribution wholesale supply point to the City of Grand Forks municipal utility and serves approximately 740 indirect customers. Thus, at winter peak, the Grand Forks Terminal T1 transformer supplies over 40 MW of load and a total of over 4,200 customers.

As described above, the T1 transformer is backed-up via two 63 kV transmission circuits (9 and 10 Lines) from Warfield. If the transformer is out-of-service for an extended period (either planned or forced), then the Grand Forks area load must be supplied from these two lines. Since an internal failure could potentially result in the T1 transformer being unavailable for a year or more, the two 63 kV circuits must currently be maintained such that they are available to reliably supply the Grand Forks area for an extended period.

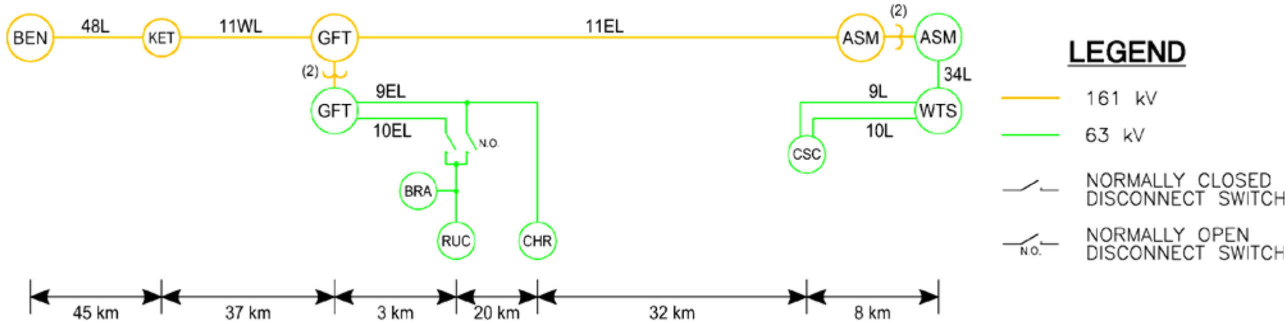
These transmission lines were originally built in 1918 and much of the construction between Rossland and Christina Lake still consists of the original poles and wire infrastructure. The two lines run in a common right of way for approximately 32 km over the Rossland Range of the Monashee Mountains and thus the majority of the line route exceeds 1,000 metres in elevation. Due to the high elevation, harsh terrain and exposure to trees, the lines experience frequent (1 to 3 outages per month) and occasionally long duration (1 day or more) outages particularly during the winter season due to snow unloading and tree contacts. This compares to FortisBC's average 63 kV transmission line outage rate of 2.1 outages per year (for 2010). In the summer, the high elevation makes the lines a frequent target of lightning-caused outages. Access to the right of way for maintenance and repairs is poor. In the winter, there are significant periods where the lines can only be accessed via snowmobile, snow-cat or helicopter. Additionally, the lines parallel an underground high-pressure natural gas line; crossing the pipeline right of way with heavy vehicles (such as a line truck) requires special permits and/or temporary bridges. Finally, both circuits also have distribution underbuild and there have been occurrences where transmission-to-distribution contacts have resulted in damage to customer equipment due to overvoltage events.

These lines have not undergone condition assessment since the early 2000s and the most recent major rehabilitation work was undertaken in 2005. At that time approximately 140 of 1,600 structures were repaired, replaced or stubbed. Given the age, condition and historical reliability of the lines, FortisBC expects that a significant amount (30% to 50%) of the lines will require rebuilding in the near future. This represents approximately 20 to 30 km of 63 kV transmission line salvage and construction in a remote area.

However, simply rebuilding the lines within the existing right of way does not resolve most issues described above. The elevation, terrain, weather, and presence of distribution underbuild would continue to negatively impact ongoing operational/capital costs, reliability and safety and thus the Company considered alternate transmission reinforcement solutions.

A practical alternate solution would be to install a second 161/63 kV transformer T2 at the Grand Forks Terminal. The station was originally laid-out for this second transformer; thus, no new land acquisition would be required and all construction would be contained within the existing fence-line. Rather than purchasing a new transformer, a 60 MVA 161/63 kV transformer recently removed from the Oliver Terminal as part of the Okanagan Transmission Reinforcement project could be reused. The ex-Oliver unit is very similar to the existing Grand Forks Terminal T1 transformer and would make parallel operation of the two transformers feasible. Installation of this second transformer would provide the Grand Forks area 63 kV transmission system with both full N-1 reliability and sufficient capacity out to (and beyond) the planning horizon. Finally, the presence of the second transformer would remove the need to maintain a 63 kV backup supply from Warfield. This would allow the salvage of approximately 64 km (approximately 830 structures) of aging transmission line between Rossland and Christina Lake. This would reduce the line length exposed to faults and requiring ongoing maintenance by over 50 percent. The final proposed configuration is shown in Figure 3.1.3 (b) below.

Figure 3.1.3 (b) - Proposed (2015) Boundary / Grand Forks Area Transmission System



Further comparison of the line rebuild versus the transformer installation options is discussed in the Options Analysis and Recommendation sections below.

Okanagan / Kootenay Communication System Limitations

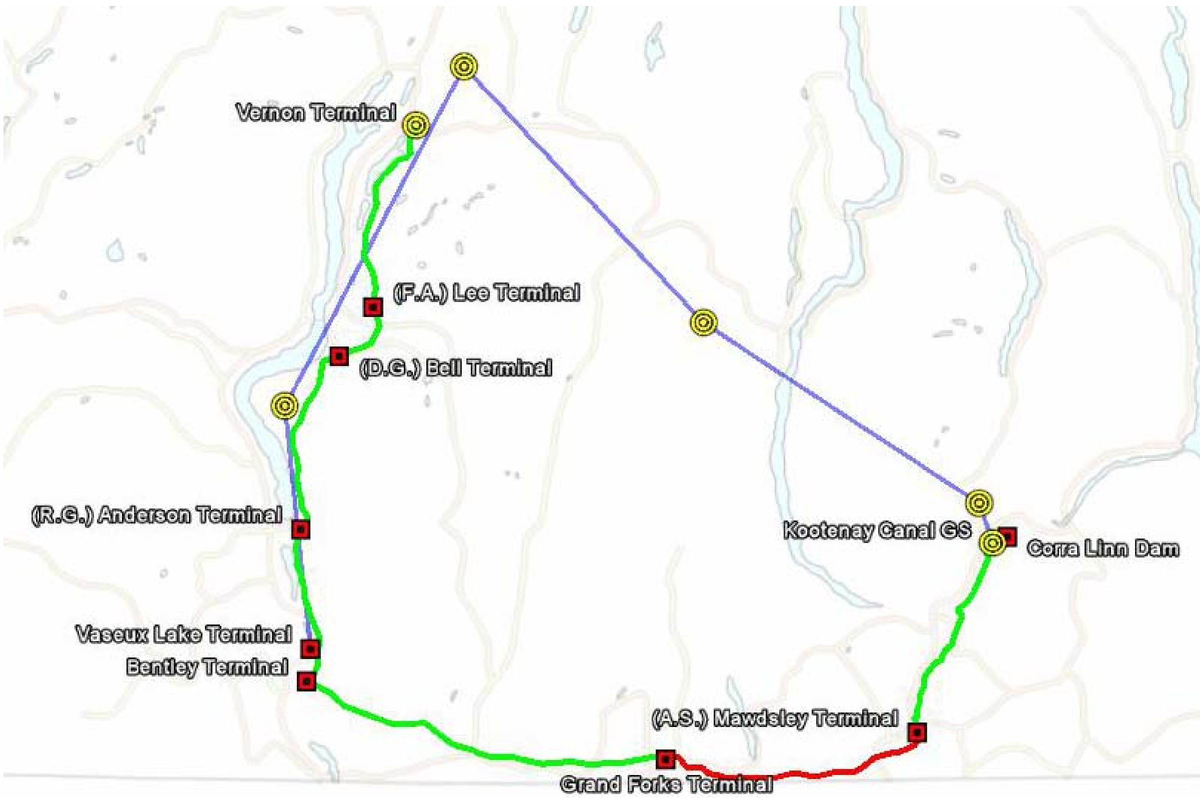
FortisBC operates two high-capacity fibre-optic backbones, one in the Kootenays and one in the Okanagan. These backbone networks are used to carry critical operational traffic such as teleprotection signaling, Remedial Action Scheme (RAS) communications, SCADA monitoring/control data, and voice communications circuits. As a secondary function, these fibre backbones are also used to provide low-cost yet high-bandwidth data communications between offices and substations for corporate wide-area network (WAN) purposes.

Presently, there is a gap between the two backbones as there is no fibre optic cable installed between Grand Forks and Warfield. This gap between the fibre backbones is currently mitigated by the use of leased communications from TELUS (for WAN purposes) and by a small number of data channels provided by the BC Hydro microwave system (for operational purposes). In the case of the WAN leased circuits, there is a significant (approximately $50,000 per year) ongoing operational cost associated with this service. In the case of the operational circuits, the bandwidth offered by BC Hydro is barely sufficient for present operational circuits and there is no additional capacity to accommodate future growth.

It should be noted that FortisBC System Control Centre (SCC) is connected to the Kootenay fibre backbone, while the majority (approximately two thirds) of the Company load is located in the Okanagan, Similkameen and Boundary regions which are interconnected via the Okanagan fibre backbone. As a result, the Company is currently completely dependent on third-party providers for operational communications between the SCC and the supply substations in the most populous portion of the service territory. Extended length (> 2 hours or more) failures of the third-party communications systems have occurred on a regular (multiple times per year) basis and these communications outages directly impact the ability of the SCC to safely and reliably operate the interconnected system. In comparison, FortisBC's fibre-optic systems have a historical reliability approaching 99.9999 percent (less than one minute of outage per year).

Figure 3.1.3 (c) shows the existing fibre backbones (in green), the gap between the two systems (in red) and the existing BC Hydro low-speed leased circuits (in blue).

Figure 3.1.3 (c) - FortisBC Communications Backbone Infrastructure



In its 2011 Capital Expenditure Plan application, FortisBC proposed to install fibre-optic cable between Grand Forks and Warfield which would eliminate the communications gap. In that application, approval for only engineering/estimating expenditures was sought, with a subsequent application to propose procurement and installation of the fibre cable. At the time, the Commission denied approval for the preliminary costs and requested that a CPCN be filed for the project. In its decision, the Commission determined, *inter alia*,

> *"…this infrastructure has significant excess capacity which has not been adequately identified. Furthermore, opportunities for its potential utilization have not been sufficiently explored." [p. 40, BCUC Order G-195-10 and associated Decision]*

Since that time, FortisBC has been able to enter into a binding agreement with a third-party communications provider who has committed to a long-term lease of a significant number of fibres along this route. The ongoing annual revenue resulting from this agreement equates to a current-day NPV of approximately $2.5 million. This represents a significant financial benefit to FortisBC customers as this Other Income goes directly to reducing revenue requirements. This agreement (which is conditional on Commission approval of the complete Grand Forks to Warfield fibre build) is essentially a “one-time” opportunity to FortisBC customers as the option to lease expires in April 2014.

The installation of fibre-optic communications between Grand Forks and Warfield can also be used to offset substation infrastructure which would otherwise be required to support the addition of the Grand Forks Terminal T2 transformer proposed above. The high-speed, dependable, and secure communications from Grand Forks to the Kettle Valley substation and A.S. Mawdsley substations would allow a reduction from a full four-breaker ring bus to a simpler single-breaker option on the 161 kV portion of the station. A similar arrangement was justified and constructed as part of the FortisBC Kettle Valley Substation project. This reduction in station equipment is not possible if the fibre-optic link between Grand Forks and Warfield is not constructed. For this reason, FortisBC has linked these projects together in order to fully represent the costs and benefits of the fibre construction along with the transformer addition.

Options Analysis

In order to fully consider the total costs to mitigate both the transmission reliability issues in Grand Forks and the lack of high-capacity communications between the Okanagan and Kootenay regions, three options were identified:

- Option 1: Construct a high-capacity fibre link between Grand Forks and Warfield in 2012/13 and install Grand Forks Terminal T2 transformer with a minimal-bus arrangement in 2014/15.

Table 3.1.3 (a) - Detailed Yearly Work Plan

Year	Work Plan - Option 1
2012	Transport and store ex-Oliver T1 transformer at Grand Forks Terminal. Condition assessment of 9L/10L. Complete engineering design for Grand Forks/Warfield fibre installation. Procure fibre-optic cable.
2013	Condition assessment of 9L/10 (if unable to complete previous year). Install fibre optic cable between Grand Forks and Warfield.
2014	Complete engineering design for Grand Forks T2 installation.
2015	Install Grand Forks T2 transformer. Salvage 9L/10L between Rossland and Christina Lake.

- Option 2: Install Grand Forks Terminal T2 transformer with a full ring-bus in 2014/15 and continue to rely on third-party communications between Okanagan and Kootenays.

Table 3.1.3 (b) - Detailed Yearly Work Plan

Year	Work Plan - Option 2
2012	Transport and store ex-Oliver T1 transformer at Grand Forks Terminal. Condition assessment of 9L/10L.
2013	Condition assessment of 9L/10 (if unable to complete previous year).
2014	Complete engineering design for Grand Forks T2 installation and full four-breaker 161 kV ring bus.
2015	Install Grand Forks T2 transformer and construct ring bus. Salvage 9L/10L between Rossland and Christina Lake.

- Option 3: Rebuild 9L/10L over a period of years (2014-17 proposed) and continue to rely on third-party communications between Okanagan and Kootenays

Table 2.8.3 (c) - Detailed Yearly Work Plan

Year	Work Plan - Option 3
2012	Condition assessment of 9L/10L.
2013	Condition assessment of 9L/10 (if unable to complete previous year).
2014-17	Rebuild 9/10 Lines as required.

FortisBC has not proposed a "Do nothing" option as it is not considered financially prudent or Good Utility Practice. As discussed previously, given the age, condition and historical reliability of 9 and 10 Lines, the Company expects that large portions of these lines will require rehabilitation/rebuilding in the near to medium-term. If the required expenditures are deferred, then the ongoing risks associated with transmission line failures such as long-duration customer outages, potential public and environmental safety risks and potential customer over-voltages due to transmission to distribution contacts will be incurred for longer than necessary. As a result, a significant amount of capital expenditures are inevitable in order to mitigate these risks.

Additionally, at some point, the necessity for a high-capacity communications link between the Okanagan and Kootenay fibre-optic systems will become mandatory. This will occur either due to BC MRS compliance requirements, the need for additional bandwidth to support future Smart Grid projects, for reliability/operational reasons or to reduce ongoing leased communications costs. FortisBC reemphasizes that it has received firm agreement from a third-party communications provider interested in leasing excess dark fibre along the proposed route. The ongoing lease revenue over the period of this agreement equates to an NPV of $2.5 million in 2011 dollars. The agreement is subject to both Commission approval to construct the project and to FortisBC commissioning the fibre by April 2014. If the determination of whether to invest in the line rebuilding or the transformer addition is deferred, then this one-time opportunity for FortisBC customers will be lost.

In all three options a condition assessment of 9 and 10 Lines between Rossland and Grand Forks has been included in the cost analysis. This condition assessment will provide a detailed estimate of the actual line rebuild work that is required (and is not currently available). In the case of Options 1 and 2, this will be used to confirm that installing the second transformer at the Grand Forks Terminal in 2014/15 is the still the optimal solution compared to the option of rebuilding the lines. In the case of Option 3, the condition assessment is required to determine the actual scope of the line rebuilds. Since no detailed condition assessment information currently exists, the analysis has assumed that approximately 40 percent of total line length requires rebuilding.

Recommended Option

The three alternatives are similar from a long term financial perspective. Table 2.8.3 (d) below details comparison of the benefits provided by each option:

Table 3.1.3 (e) - Comparison of Benefits by Option

Benefits	Option		
	1	2	3
Provides N-1 transmission reliability for Grand Forks area	X	X	X
Minimizes substation construction at the Grand Forks terminal	X		X
Allows salvage of 9 and 10 Line between Rossland and Christina Lake	X	X	
Reduces exposure to transmission/distribution underbuild over-voltage events	X	X	
Provides high-capacity communications between Okanagan and Kootenays	X		
Reduces dependence and ongoing lease costs for third-party telecommunications	X		
Provides opportunity for additional ongoing revenue from surplus fibre leases	X		
Takes advantage of spare transformer from Oliver station	X	X	
Lowest environmental and public impact from transmission line infrastructure	X	X	

Based on the analysis above, the recommended option is Option 1. Most significantly, this option provides the desired high-capacity communications link between Grand Forks and Warfield for only a $0.5M incremental NPV cost. Thus, the solution provides the best long-term value to FortisBC customers as it meets the requirements of providing a reliable 63 kV transmission supply for the Grand Forks area in addition to providing a reliable, high-capacity link between the existing Okanagan and Kootenay communications networks.

In this Application, FortisBC is only seeking approval for expenditures related to the relocation and storage of the transformer at the Grand Forks Terminal, the condition assessment of 9 and 10 Lines, and for the construction of the fibre optic link between Grand Forks and Warfield.

Approval for expenditures related to the installation of the transformer (and construction of associated substation works) as well as the salvage costs for the 63 kV transmission lines will be the subject of a future Capital Expenditure Plan application (currently proposed for 2014/15).

This project is estimated to cost $2.49 million in 2012, $4.71 million in 2013 and an additional $8.82 million in 2014 - 2015.

3.1.4 KELOWNA BULK TRANSFORMER CAPACITY ADDITION

The addition of a new power transformer is required to provide adequate transformation capacity to supply the Kelowna area load during single contingency (N-1) outage conditions. Customers in Kelowna and the surrounding areas are currently served by two 230/138 kV terminal stations: the FA Lee Terminal Station which contains two 168 MVA 230/138 kV transformers and the DG Bell Terminal Station which contains one 200 MVA 230/138 kV transformer.

The need for the additional capacity was identified in past transmission planning studies as being driven by Kelowna area load growth. The need, however, has been advanced with the transfer of the BC Hydro Winfield area load to the FortisBC Duck Lake substation in 2011. Previously, this load was supplied directly by BC Hydro via a 69 kV radial transmission line from BC Hydro's Vernon Terminal. This transmission line and associated substation facilities were faced with imminent capacity and condition-related issues. A number of project alternatives were considered by BC Hydro to resolve the Winfield supply issue, with the recommended alternative being to expand the existing FortisBC Duck Lake substation to provide a 25 kV distribution supply to BC Hydro customers. This arrangement was formally identified in the Duck Lake Wheeling Agreement and was approved by the Commission in Order G-19-10. In the Wheeling Agreement it was identified that the joint FortisBC / BC Hydro solution would provide greater reliability for BC Hydro customers compared to a BC Hydro network upgrade solution. The Duck Lake upgrade also minimized environmental and social impacts by using existing transmission and substation facilities. From a financial perspective, BC Hydro customers were cost-neutral compared to a BC Hydro-only system upgrade, while FortisBC customers would benefit from the rate mitigation provided by the ongoing wheeling revenue. On that basis, the Wheeling Agreement satisfied the direction from the BC Utilities Commission for BC Hydro to find a solution which benefits both utilities.

Table 3.1.4 below shows the transformer loadings for all relevant contingencies, as determined by power flow simulation studies. Following the outage of one of the two existing FA Lee Terminal transformers, the load on the remaining transformer exceeds its emergency overload rating when the total Kelowna area load reaches 369 MW. This condition constitutes a violation of BC Mandatory Reliability Standard TPL-002, which requires that applicable thermal ratings are not exceeded following the loss of a single element. The standard requires that corrective plans must be implemented to eliminate the violation. In the 2012-15 timeframe the overloads can be mitigated by reconfiguring the Kelowna transmission system during peak load conditions. This is performed by moving normally-open switching points in the Kelowna 138 kV transmission system to transfer load from the FA Lee Terminal to the DG Bell Terminal.

This system reconfiguration is not effective beyond 2014-15, as the supply from DG Bell is removed for an outage of 73 Line, which at that time becomes the critical contingency.

Mitigation will, therefore, require one of the options described below and must be implemented before winter 2015-16.

Table 3.1.4 - Kelowna Transformation Capacity - Load Flow Analysis

KELOWNA WINTER PEAK LOAD (MW)	CONDITION	YEAR (WINTER)	POWER FLOW IN % OF NORMAL OR EMERGENCY RATING		
			LEE		DGB
			T3	T4	T2
	All elements in service		81	79	55
369	LEE T3 out	2012-13	-	101	59
	DGB T2 out		86	85	-
	73L out (RGA-LEE)		90	89	-
	All elements in service		84	83	57
384	LEE T3 out	2013-14	-	106	61
	DGB T2 out		90	89	-
	73L out (RGA-LEE)		96	95	-
	All elements in service		84	82	66
395	LEE T3 out	2014-15	-	103	69
	DGB T2 out		94	93	-
	73L out (RGA-LEE)		100	100	-
	All elements in service		86	85	67
407	LEE T3 out	2015-16	-	106	70
	DGB T2 out		96	96	-
	73L out (RGA-LEE)		104	104	-
	All elements in service		89	89	67
417	LEE T3 out	2016-17	-	110	72
	DGB T2 out		99	99	-
	73L out (RGA-LEE)		108	108	-

The following viable mitigation options have been identified and are currently being assessed in preparation for an application for a Certificate of Public Convenience and Necessity (CPCN) to be filed in early 2012:

1. Install a third 230/138 kV transformer at the FA Lee Terminal.
2. Install a second 230/138 kV transformer at the DG Bell Terminal.
3. Install a new 230/138 kV transformer on a new property adjacent to the existing Duck Lake substation.

In the early screening stage three additional alternatives were identified and deemed not feasible. Options considered and rejected were;

- A do nothing approach was considered and rejected. There are two reasons why this is not a viable option. First, compliance with BC Mandatory Reliability Standard TPL-002 is required and thus the project is deemed to be non-discretionary. Second, a shortage of bulk transformer capacity could cause potentially lengthy customer outages during peak and near-peak winter conditions, resulting in a level of customer service which is well below established standards.
- The option to install firm generation resources near Kelowna connected to the 138 kV transmission system was considered and rejected. This option would significantly reduce the loads of the existing transformers at the FA Lee and DG Bell Terminals and would eliminate the need to add new transformer capacity for several years. However, due to its high cost this option would be viable only if the generation were also required to meet resource planning needs. Due to the additional capacity which FortisBC will acquire through the Waneta Expansion Capacity Purchase Agreement there is no requirement for additional capacity resources, at least not in the 2014-15 timeframe. Compared to the estimated cost of a transformer capacity addition, the cost of a generation resource option is prohibitive, as it is estimated at $44 million for 39 MW of gas fired generation. The amount of generation required to make this option equivalent to the proposed solution is approximately 227 MW, equal to the emergency rating of the proposed transformer. The cost far exceeds that of the proposed solution and this option is dismissed.
- Install a new 230/138 kv transformer adjacent to Black Mountain substation. This option is electrically equivalent to Option 2 above. However, the land needed to accommodate the substation expansion is contained within the Agricultural Land Reserve (ALR). This option is dismissed as it does not offer any system performance advantages over option 5, and also has the additional uncertainty related to removal of the required lands from the ALR.

At this time FortisBC is forecasting expenditures of $3.72 million in 2013 in order to meet the required project in-service date of winter 2015/16. The Company expects to file an application for a CPCN for the Kelowna Bulk Transformer Capacity Addition project in early

2012. This CPCN will contain a detailed option analysis, information on the recommended solution and a revised project cost estimate and expenditure schedule.

3.2 Transmission Sustainment Programs and Projects

Table 3.2 - Transmission Sustainment

1		2012	2013	Total
2	**Transmission Sustainment**		**($000s)**	
3	Transmission Line Condition Assessment	522	485	1,007
4	Transmission Line Rehabilitation	3,372	2,621	5,993
5	Transmission Line Urgent Repairs	594	620	1,214
6	Transmission Line Right-of-Way Easements	400	400	800
7	6 Line /26 Line River Crossing Reconfiguration	1,185	-	1,185
8	27 Line Rebuild	1,161	-	1,161
9	21-24 Lines Rebuild	2,219	-	2,219
10	19 Line/29 Line Reconfiguration	-	791	791
11	20 Line Rebuild	-	4,664	4,664
12	**Total Transmission Sustainment**	**9,453**	**9,581**	**19,034**

3.2.1 Transmission Line Condition Assessment

The transmission system requires a proactive program to manage the risk to employee and public safety, and to ensure an acceptable level of service to FortisBC customers.

The transmission line condition assessment program is based on an eight-year cycle of inspecting and testing all FortisBC transmission line facilities in order to extend the life of the pole and ensure the integrity of the lines. The program consists of a test and treat component and an above ground visual condition inspection. The test and treat component of the program is aimed at the section of pole at the ground level and below and consists of drilling test holes in each pole to identify internal rot and adding pole treatment into the hole to reduce internal rot. The above ground visual inspection focuses on the condition of the pole itself and all equipment (anchoring, cross-arms, insulators, guying and grounding) above ground. If an issue is detected during the condition assessment the deficiency is documented and corrected under the following year's transmission rehabilitation budget.

The program is managed in an eight-year cycle to levelize both the budget and the resources required. The condition assessment project will assess the following lines in 2012 and 2013. Appendix G to FortisBC's 2012 Long Term Capital Plan provides further detail on the conduct of condition assessments and identification of deficiencies for the transmission system.

Table 3.2.1 (a) - 2012 Transmission Line Condition Assessment Projects

Line	Location	Poles
9	Warfield Terminal Station to Cascade	88
10	Warfield Terminal Station to Cascade	88
11E	Warfield to Grand Forks	542
19	South Slocan to Valhalla	538
48	Kettle Valley to Bentley	431

Table 3.2.1 (b) - 2013 Transmission Line Condition Assessment Projects

Line	Location	Poles
6	Brilliant - Ootischenia -Blueberry - Castlegar - Zellstoff Celgar	356
18	Waneta to Beaver Park	99
26	Brilliant - Ootischenia -Blueberry - Castlegar - Zellstoff Celgar	353
32	Crawford Bay to Lambert	747

The following table shows the actual expenditures for the transmission line condition assessment project from 2007 to 2010 as well as the forecast expenditures for 2011 and the plan for 2012 and 2013. The estimates for 2012 and 2013 are derived by applying a total cost required to assess the structure (based on historical information and contractual agreements) to the number of transmission poles being assessed. This number is then adjusted for inflation and overhead loading.

Table 3.2.1 (c) - Transmission Line Condition Assessment Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
152	639	413	343	469	522	485

3.2.2 TRANSMISSION LINE REHABILITATION

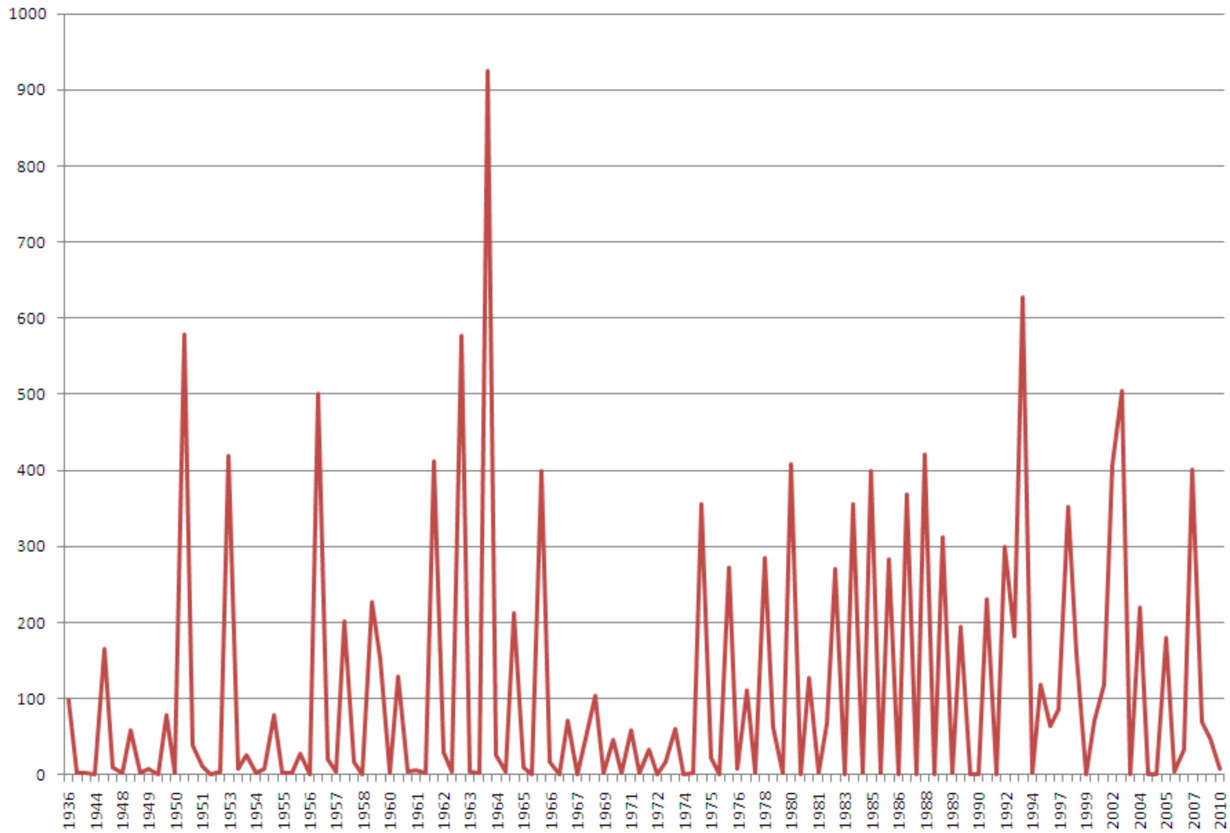
The rehabilitation project for transmission lines involve expenditures for stubbing poles, replacement of poles, cross-arms, guy wires, as well as replacing other defects identified for rehabilitation in the previous year's assessments. This project is required to address public and employee safety issues, environmental concerns and maintain reliable electrical service to FortisBC customers. In 2012 and 2013 the Company will undertake rehabilitation of the transmission lines assessed in 2011 and 2012 respectively. Table 3.2.2 (a) below outlines the transmission lines scheduled to be rehabilitated in 2012. Table 3.2.1 (a) above outlines the lines that will be rehabilitated in 2013 following completion of the necessary assessments in 2012.

Table 3.2.2 (a) - 2012 Transmission Line Rehabilitation Locations

Line	Location	Poles
9E-2	Grand Forks to Ruckles to Christina Lake	364
10E-2	Grand Forks to Ruckles to Christina Lake	353
43	Bentley to Princeton	1,403
43A	Tap to Apex mine	71

FortisBC has 62 transmission lines consisting of approximately 1,400 kilometres of line and 15,000 poles. The following graph shows, as of 2010, the vintage and quantity of poles within FortisBC's transmission system. There are approximately 3,000 (20 percent) poles in the FortisBC transmission system that are older than 50 years. Not shown on the graph are an additional 1,944 poles for which the date is not known for various reasons (pole is weathered due to age and cannot be read, no records from when it was installed, etc) but which are also assumed to be older than 50 years. Based on this, almost 33 percent of the transmission poles in the FortisBC system are older than 50 years. As the average life expectancy of a wooden transmission pole is approximately 40-60 years, based on Company experience, the transmission rehabilitation budget will likely need to be increased to accommodate the large quantity of poles that will need to be replaced within the near future. As shown in Figure 3.2.2 below, a large number of poles in the system are already at or nearing the 40-50 year old mark. Figure 3.2.2 also outlines that in some rare cases transmission poles last longer than 50 years due to geographic location, species, and pole class, but on average 40-60 years of life expectancy is typical.

Figure 3.2.2 - Transmission Poles vs. Pole Vintage



In order to complete rehabilitation work in the year immediately following the condition assessment patrol, the estimates for this budget are not based on actual field assessed data as the Company would need condition assessment data in 2010/2011 for the rehab work requesting to be done in 2012/2013. Rather, the estimates for this budget are based on historical information of costs on a per pole basis, adjusted for inflation and changes to overhead loading, and knowledge of the transmission lines being assessed. The following table shows the actual expenditures for the transmission line rehabilitation program for the years 2007 to 2010 as well as the forecast amount for 2011 and plan for 2012 and 2013.

Table 3.2.2 (b) - Transmission Line Rehabilitation Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
1,051	1,329	1,441	1,905	1,604	3,372	2,621

3.2.3 Transmission Line Urgent Repairs

The Urgent Repairs project is required to replace component failures or components that are in poor condition and in danger of immediate failure on the transmission system due to weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions or other unexpected reasons that can cause outages or present risks, and must be addressed in an expedient manner. The project is required to address public and employee safety issues, address environmental concerns and maintain reliable service to FortisBC customers.

The planned expenditures for this program are based on a three-year rolling average of historical expenditures from 2008 to 2010, adjusted for inflation and changes to overhead loadings. The three-year rolling average method is used to derive this budget as FortisBC cannot foresee the range of dynamic variables in the future that would affect this budget. Using historical spending patterns to predict the basis of upcoming years' budgets is the most logical approach from FortisBC's perspective. The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and plan for 2012 and 2013.

Table 3.2.3 - Transmission Line Urgent Repairs Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
514	362	526	487	491	594	620

3.2.4 Right of Way Easements

This project is required for acquiring rights of way and easements for existing transmission facilities that cross over private property in trespass. Easements for new projects are obtained as part of the new project and are not included in this estimate. Expenditures for this budget will also address access issues with respect to existing rights of way. Many of the transmission lines, when initially constructed, did not have formal road access to sections of the right of way. Access is required for operation and maintenance of these lines.

The planned expenditures for this program are based on a three-year rolling average of historical expenditures from 2008 to 2010, adjusted for inflation and changes to overhead loading. The three-year rolling average method is used to derive this budget as FortisBC cannot foresee the range of dynamic variables in the future that would affect this budget.

Using historical spending patterns to predict the basis of upcoming years' budgets is the most logical approach from FortisBC's perspective. The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and plan for 2012 and 2013.

Table 3.2.4 - Transmission Right-of-Way Easements Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
170	135	235	118	358	400	400

3.2.5 6 Line/26 Line River Crossing Reconfiguration

Both 6 Line and 26 Line originate at the Brilliant Switching station and split off into four transmission lines that cross the Kootenay River at two locations, one on the upstream (eastern) and one on the downstream (western) side of the Brilliant Bridge on Highway 3A. This creates two dual source supply lines for the Castlegar area current configuration, as shown in Figure 3.2.5 (a) below. One loop supplies the Castlegar substation, Interfor Forest Products and ties in with Zellstoff Celgar while the other loop supplies the Ootischenia and Blueberry distribution substations.

This project involves work on the transmission lines on the upstream and the transmission and distribution lines on the downstream side of the bridge crossing the Kootenay River at the north east end of Castlegar.

In 2009, FortisBC experienced a pole top failure on one of the distribution river crossing structures, resulting in a live conductor falling into the Kootenay River. The Company/external consultant performed an engineering analysis on the remaining river crossing structures and all structures except one, which was replaced six years ago (6L19), showed various signs of requiring rehabilitation or replacement. Four structures were recommended to be replaced in a non urgent manner in the next capital expenditure plan, one structure was considered to be marginal and could possibly last for another eight year cycle and two structures do not have a sufficient pole diameter for current standards.

Various options were explored to determine how to best rehabilitate the crossings, including a like for like rehabilitation of all four river crossings. It was determined that it would be more efficient from an operational and environmental perspective to salvage the upstream transmission river crossings and to create a new tap point between the loops of 6 Line and 26 Line, as shown in the Figure 3.2.5 (b) below after reconfiguration than to rehabilitate all four river crossings like for like.

The reconfiguration will reduce the ongoing capital rehabilitation expenditures required to maintain the lines through the condition assessment program. It will also reduce public safety and environmental risk exposure from river crossing failures by eliminating two long redundant spans of conductor across the Kootenay River which is heavily populated with a wide variety of fish including Sturgeon. Figure 3.2.5 (b) below shows at a high level the change required to eliminate the two river crossings.

Figure 3.2.5 (a) - 6 Line/26 Line River Crossing Reconfiguration - Before

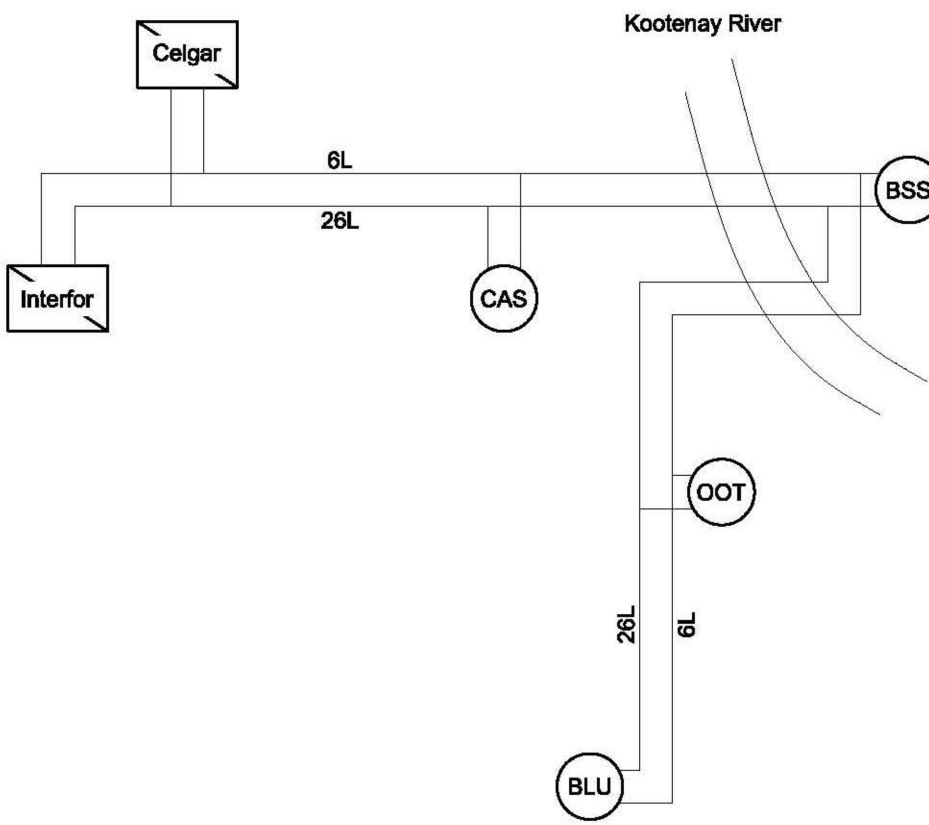
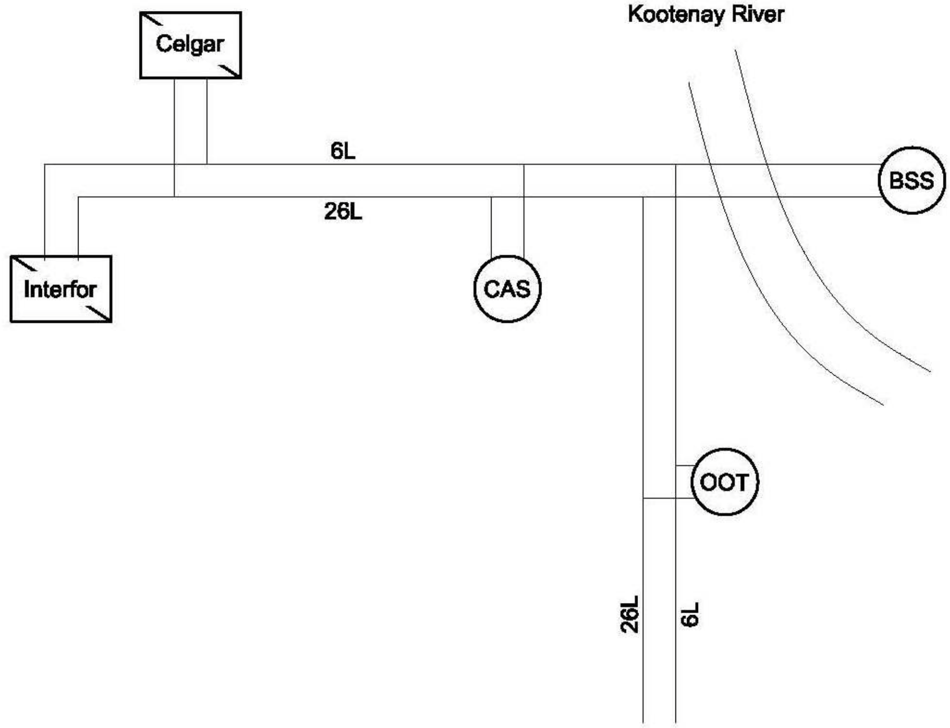


Figure 3.2.5 (b) - 6 Line/26 Line River Crossing Reconfiguration - After



The project is estimated to cost $1.19 million in 2012. Further detail regarding this project is contained in FortisBC 10 Transmission Rebuild Plan, provided as Appendix F to FortisBC's 2012 Long Term Capital Plan.

3.2.6 27 LINE REBUILD

This project is required to maintain service reliability and alleviate safety concerns for the customers in the Nelson, Whitewater, Ymir and Salmo areas. 27 Line is a 63 kV circuit that was constructed in 1930. It is approximately 57 kilometres in length and runs from Corra Linn to Salmo with Rosemont Switching Station, Cottonwood, and Ymir substations in between. 27 Line has a variety of configurations consisting primarily of three-phase and single-phase distribution underbuild, as well as some single circuit transmission with no underbuild. The line has many sections with significant setback from the highway and is generally on its own separate right of way. There have been some structure changes to the line over the years; but there are still many structures that are either "red tagged" for replacement or stubbed beyond the recommended life extension period including structures with significant pole top and crossarm rot.

In 2007/08 a detailed engineering assessment was conducted on the line to address reliability and safety concerns reported over the past several years. The assessment concluded that in general the circuit is in poor condition with numerous steel stubbed structures in urgent need of replacement, substandard circuit spacing, and areas with insufficient anchoring. The deficiencies noted have been reviewed and documented on an individual structure basis and a detailed work scope has been formulated. The report considered several options including rebuilding sections on opposite sides of the road, and providing an alternate source of 63 kV to any of the load centers, however these were eliminated as not being feasible.

In 2010 the detailed engineering assessment report was updated to reflect a more accurate scope of work, considering that many structures had already been replaced under urgent repairs and as a priority under the 2009 rehabilitation budget, using up to date pricing. The report concluded that 84 structures require repairs and 14 structures require replacement. The chart on the following page shows the pole vintage distribution along with the counts of which structures are recommended for replacement.

This project is estimated to cost $1.16 million in 2012. Further detail regarding this project is contained in FortisBC 10 Transmission Rebuild Plan, provided as Appendix F to FortisBC's 2012 Long Term Capital Plan.

3.2.7 21 - 24 LINE REBUILD

21 - 24 Lines interconnect all four FortisBC owned river plants on the Kootenay River. Line 21 is 2.1 kilometres long and spans from the South Slocan plant to the Lower Bonnington plant. Line 22 is 3.6 kilometres long and spans from the South Slocan plant to the Upper Bonnington plant. Line 23 is 5 kilometres long and interconnects all four river plants spanning from South Slocan plant to the Corra Linn plant. Line 24 is also 5 kilometres long and spans from the South Slocan plant to the Corra Linn plant. These lines are all 60 or more years of age and in very poor condition. Similar to both 20 Line and 27 Line a detailed engineering assessment was done in 2008 to identify the deficiencies and risks and explore some options for rebuild. The outcome of the study was to do a like for like replacement of the structures over about a 10-15 year period of time but to replace all urgent structures in the next capital plan. Like the 20 Line and 27 Line assessment reports, the 21-24 Line report was also updated for submission in the 2012-13 Capital Plan with up to date scopes and estimates. During the next couple of condition assessment/rehabilitation cycles the

remaining substandard condition structures would be replaced to reduce the effects of the large capital expenditure in one capital plan. Outages on these lines can potentially have large financial implications if the outages result in a generator forced outage. Scope for this project is very similar to the 20 and 27 Line rebuilds with mainly structure replacement. Line 21 requires 10 structure replacements, Line 22 requires 23 structure replacements, Line 23 requires 29 structure replacements and Line 24 requires 37 structure replacements for a total of 99 structure replacements. Appendix A to the 2012-13 Capital Plan (Tab 7) provides a summary of all deficiencies identified on each structure identified for repair or replacement.

This project is estimated to cost $2.22 million in 2012. Further detail regarding this project is contained in FortisBC 10 Transmission Rebuild Plan, provided as Appendix F to FortisBC's 2012 Long Term Capital Plan.

3.2.8 19 Line /29 Line Reconfiguration

This project involves the transfer of load from 19 Line to 29 Line at the South Slocan switching station and the salvage of 19 Line from the South Slocan switching station to a termination point south of the Passmore substation.

19 Line and 29 Line both originate at the South Slocan switching station and generally run north in the same right of way corridor until they cross Highway 6 just south of the Passmore substation. From this point, 19 Line continues north radially to the Passmore and Valhalla substations while 29 Line is terminated. At this termination point there is a crossbus with inline openers that tie 19 Line and 29 Line together. Figure 3.2.8 (a) below shows the current configuration of the lines. Historically, 29 Line continued on to Vernon, however now the section of 29 Line after the termination is used as part of Passmore Feeder 1.

At the present time the 12.5 kilometre section of 19 Line that runs in parallel with 29 Line from South Slocan Switching station is in very poor condition and requires rehab/rebuild. As well there is no justification for maintaining both lines that ultimately source the load radially. Since 29 Line in this corridor has recently undergone extensive rehabilitation and is the preferred line to continue to maintain, 19 Line will be salvaged. Figure 3.2.8 (b) below shows the proposed future configuration of the lines.

Figure 3.2.8 (a) - 19 Line/29 Line Current Configuration

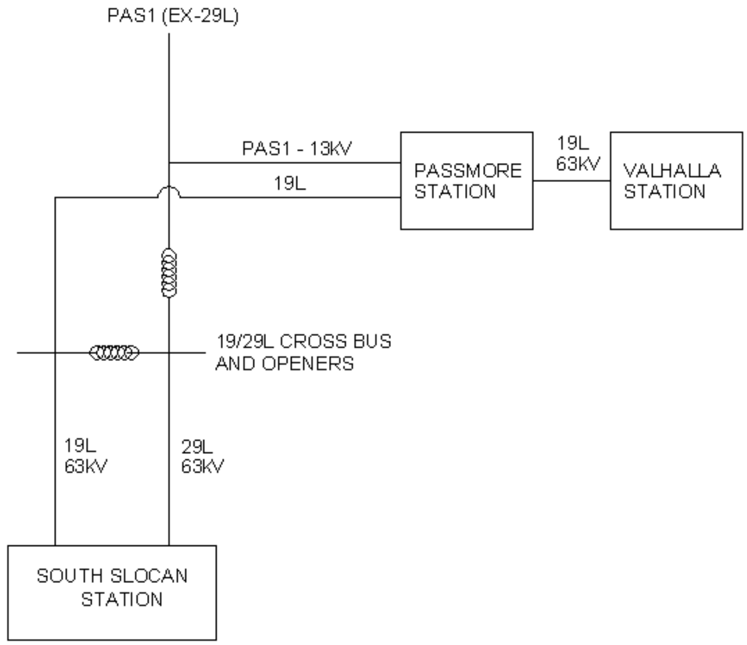
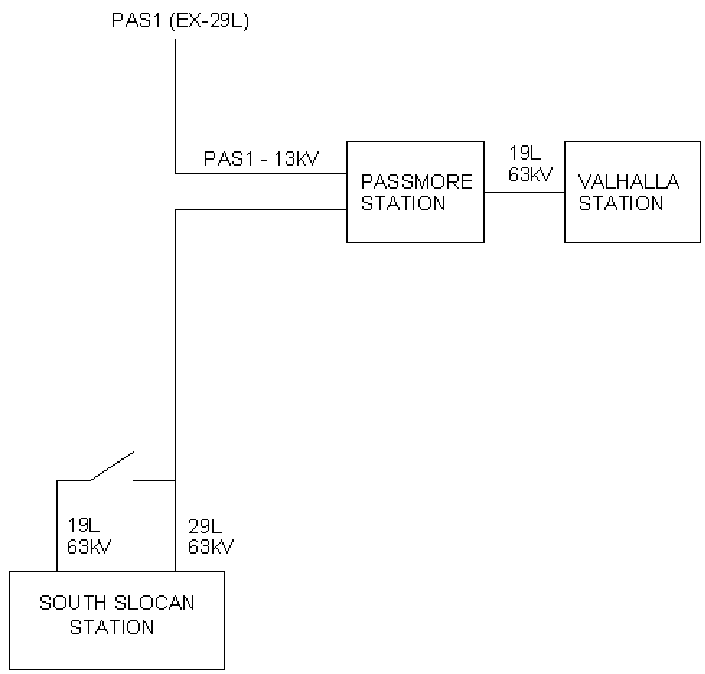


Figure 3.2.8 (b) - 19 Line/29 Line Future Configuration



This project is estimated to cost $0.79 million in 2013. Further detail regarding this project is contained in FortisBC's 10 Transmission Rebuild Plan, provided as Appendix F to FortisBC's 2012 Long Term Capital Plan.

3.2.9 20 LINE REBUILD

This project is required to maintain service reliability and alleviate safety concerns for the customers in the Trail, Waneta, Montrose, Fruitvale and Salmo areas. 20 Line is a 63 kV circuit that was constructed in 1931. It is approximately 46 kilometres in length, and runs from Warfield Terminal station to Salmo with distribution substations at Glenmerry, Beaver Park, Fruitvale, and Hearns in between. The line includes portions of three phase distribution underbuild between Beaver Park and Salmo. The Beaver Park to Salmo section is also primarily along road and highway rights-of way and is in close proximity to the tree line. Historically, only urgent repairs have been addressed.

In 2007/08 a detailed engineering assessment was conducted on the line to address reliability and safety concerns reported over the past several years. The study identified many structures that are either “red tagged” for replacement or stubbed beyond the recommended life extension period. Also identified was significant pole top and crossarm rot, further verifying end of life. The assessment concluded that in general the circuit is in poor condition with numerous steel stubbed structures in urgent need of replacement, sub-standard circuit spacing, and areas with insufficient anchoring. The deficiencies noted have all been reviewed and documented on an individual structure basis and a detailed work scope has been formulated. The report that was created considered several options including rebuilding sections on opposite sides of the road, and providing an alternate source of 63 kV to any of the load centres, however these were eliminated as not being feasible.

In 2010 the detailed engineering assessment report was updated to reflect a more accurate scope of work, considering that many structures had already been replaced under urgent repairs, using up to date pricing. The report concluded that 52 structures require repairs and 152 structures require replacement. The chart on the following page shows the pole vintage distribution along with the counts of which structures are recommended for replacement. Notice the majority of poles are older than 50 years.

This project is estimated to cost $4.66 million in 2013. Further detail regarding this project is contained in FortisBC’s 10 Transmission Rebuild Plan, provided as Appendix E to FortisBC’s 2012 Long Term Capital Plan.

3.3 Station Sustainment Programs and Projects

The Station Sustainment projects involve the rehabilitation and ongoing upgrades to the substation system. These projects are necessary to ensure continuous service of the substation system which includes transformers, breakers, batteries, ground grids and related equipment. FortisBC owns 66 substations, which include more than 2,000 major pieces of equipment, and over 2,000 protection and ancillary systems.

These projects are required to maintain service reliability for customers, a safe work environment for employees, and to address any environmental or public safety issues identified during the assessment process.

Table 3.3 - Station Sustainment Programs and Projects

		2012	2013	Total
	Station Sustainment	($000s)		
1	Environmental Compliance (PCB Mitigation)	11,269	11,553	22,822
2	Station Urgent Repairs	818	907	1,725
3	Station Assessment/Minor Planned Projects	1,343	1,354	2,697
4	Add Arc Flash Detection to Legacy Metal-Clad Switchgear	539	544	1,083
5	Huth Low Voltage Breaker Replacement (2 Units)	-	69	69
6	**Total Station Sustainment**	**13,969**	**14,427**	**28,396**

3.3.1 ENVIRONMENTAL COMPLIANCE (PCB MITIGATION)

Polychlorinated Biphenyls (PCBs) have been used in the electrical industry since the early part of the 20th century. Their stable chemical properties, along with excellent electrical insulation qualities and resistance to combustion make PCBs an ideal insulating medium in electrical equipment. Approximately 40,000 tonnes of pure PCBs were imported into Canada and used primarily in insulating fluids for electrical equipment. However, in the mid 1970s, scientists identified hazards to human health and the environment from PCBs and the goals of government environmental policy is the virtual elimination of PCBs from the environment since that time.

In 2004, the still pending federal PCB legislation was expected to be enacted within the next year which would require all in-service equipment containing PCB concentrations greater than 50 mg/kg to be inventoried and reported annually. The draft regulation also suggested that depending on level of concentration some units would be required to be removed from service, but that specified PCB containing equipment in electricity generation, transmission and distribution facilities would have an elimination deadline of December 31, 2025, but still required annual inventory reporting. As a proactive effort to ensure compliance with the pending regulation, FortisBC submitted to the BCUC as part of its 2005 Revenue Requirements Capital Plan details of the Company's proposed 8 year PCB oil sampling program. The program was primarily directed towards the testing of pole-top, underground and pad mounted transformer units. Approval was obtained from the BCUC and the testing program commenced in June 2005.

In 2006, the proposed regulatory text was released, which did not contain the expected early deadline for pole-top electrical transformers. Instead, the elimination deadline was for December 31, 2025 for pole-top electrical transformers containing more than 50 mg/kg, and for current transformers, potential transformers, circuit breakers, reclosers and bushings containing more than 50 mg/kg that are located at an electrical generation, transmission or distribution facility. In addition, the release of more than one gram of PCBs from in-service equipment was prohibited. The proposed text also stipulated that annual reporting on equipment concentration and location take place. The FortisBC oil sampling program continued to sample and test equipment to ensure compliance when the PCB legislation became law.

In September, 2008, the *PCB Regulations* were passed into law. The requirements were similar to the draft regulation proposed in 2006 with respect to pole-top electrical transformers, allowing an end of use deadline of December 31, 2025, and the prohibition against the release of more than one gram of PCBs from in-service equipment. The major and unexpected difference for industry between the final 2008 regulations and the draft proposed in 2006 was for equipment located in substations with PCB concentrations of greater than 500 mg/kg. This equipment, which includes current transformers, potential transformers (collectively called instrument transformers), and bushings, is to be removed from service by December 31, 2009 instead of industry's previous expectation of 2025 as was outlined in the 2006 draft regulations. A provision for an extension to December 31, 2014 was included in the regulations, and FortisBC applied for and received this extension. Since the *PCB Regulations* have been enacted, the Company has ceased its annual pole top testing program and will complete at a later date to ensure compliance with the new 2025 date and has focused its efforts on the PCB Mitigation Program concerned with the removal from service of contaminated instrument transformers, bushings and capacitors containing greater than 500 mg/kg by the December 31, 2014 deadline. Of note, the

Canadian Electricity Association has continued to lobby government on behalf of industry since 2008 to reinstate the 2025 date for this equipment with limited success to date.

2011 expenditures for PCB mitigation were approved by the BCUC under order G-195-10. Approved expenditures of $2.1 million dollars for 2011 are being used to mitigate contaminated equipment and plan for future removal of equipment. Defining the scope of the problem and addressing the challenges of identifying and removing this equipment from service is critical to meeting the December 31, 2014 deadline.

The first challenge associated with complying with the legislation is identifying contaminated equipment. The equipment in question is distributed throughout the Company's facilities, and the majority of it has not been tested for PCBs. Generally, and with exception, equipment manufactured after 1982 is considered to be free of PCBs, and certain manufacturers claim to have never used PCBs in their equipment. This information, along with the type of insulation in the equipment, allowed the compilation of a list of equipment suspected of containing greater than 500 mg/kg concentration of PCBs. FortisBC is working with a consulting company to identify all the proscribed equipment that is possibly contaminated and provide an estimate and work plan to remove the equipment from service and dispose of it. Using industry average contamination levels and the list of suspected contaminated equipment, a rough high and low estimate of the number of pieces of equipment that may need to be replaced has been obtained. The high estimate assumes that all suspected equipment is contaminated and requires replacement, while the low estimate assumes that FortisBC equipment will align with industry average contamination levels.

Table 3.3.1 (a) - Estimated Number of Units to be Replaced

Equipment	Industry Average Contamination	Number of Suspected Units	High Estimate of Units to be Replaced	Low Estimate of Units to be Replaced
Bulk Oil Circuit Breakers	48%	9	9	4
Transformer Bushings	45%	194	194	87
Distribution Instrument Transformers	27%	15	15	4
Instrument Transformers	27%	43	43	12
Capacitors	100%	266	266	266

There are several challenges in the assessment and replacement of the suspected contaminated equipment. First, in order to test the equipment, an outage at the substation must be scheduled, and second, the equipment may be sealed with no possibility of extracting a sample of the insulating medium to test for PCBs. Some units may also have a sampling port that is seized and thus effectively sealed, or upon opening the equipment to take a sample, the equipment may be damaged in the process beyond repair or may leak in the future. Two options have been identified to address this issue:

1. The first option is to schedule one outage to replace the suspected piece of equipment, and once the piece of equipment is removed from service, a sample of the insulating medium will be tested for PCBs. If the unit is destroyed during sampling, as in the case of a unit that is sealed, it can be disposed of according to the PCB Regulations. If the unit is found to be free of PCB contamination, it can be used to replace other suspected PCB equipment or as an operational spare, providing it meets current FortisBC equipment standards. The disadvantages of this method are that equipment may be replaced that is not contaminated with PCBs, but it will also reduce the reliability impact to customers. Based on the industry average contamination levels, 52 percent to 73 percent of the equipment (depending on the type of equipment) would be replaced unnecessarily.

2. The second option is to schedule two outages, the first for a PCB test, and the second outage in the event that the equipment requires replacement. The disadvantage to this method is that in the event that the equipment is found to contain PCBs, two outages would be necessary as opposed to a single outage in the first method. Using the industry average contamination levels, the likelihood of a second outage ranges from 27 percent to 48 percent. The advantage to this method is that only contaminated equipment, or equipment that required destructive testing, will be replaced.

Some combination of these two methods will be implemented based on actual contamination levels found. Several factors will affect which option is employed, such as:

1. The cost of replacing the equipment. For example, while the complete replacement of transformer bushings costs in the neighbourhood of $100,000, the cost of replacing three bus potential transformers is roughly $20,000. High replacement costs will favour option 2.

2. Service life remaining. Where equipment is near end of life, the likelihood of PCB contamination due to age of manufacture is greater, and the risk of a leak after the equipment has been sampled increases.

3. Co-ordination with other projects. When maintenance or other projects take place at sites with equipment suspected of PCB contamination greater than 500 mg/kg, PCB remediation work can take place where practicable.

4. Test results. As equipment replacement progresses, more data on actual contamination levels will allow for better decisions on which equipment is likely contaminated. All equipment that is replaced will be tested, as procedures for disposal of contaminated equipment differ for equipment that is not contaminated.

FortisBC substations consist primarily of single transformers with a connection for a mobile transformer. Where dual transformers are installed in the station, customer outages can be minimized. The replacement of instrument transformers will have the greatest impact on customer reliability. Potential (voltage) transformers require a complete station outage to test and/or replace. It is estimated that there may be as many as 30 sets of potential transformers to replace. At an average replacement time of eight hours per set and 2,500 customers per substation, this equates to 600,000 customer hours of lost service over the course of the program. Transformer bushing replacement will require the installation of a mobile transformer to offload the transformer while the bushings are replaced. Bushing replacement requires the insulating oil in the main tank of the transformer to be partially drained to facilitate the replacement. Overall, it is estimated that approximately 700,000 customer hours of lost service will occur during the PCB Mitigation program. This is equivalent to an incremental SAIDI impact of approximately 6 hours over the course of the program.

Another impediment to the timely completion of the program is the procurement of replacement parts. The delivery time of some instrument transformers can be up to 18 months. Older transformers may require specialized adapters to fit replacement bushings. In addition, other utilities working towards compliance to the PCB Regulations will be requiring replacement parts, further exacerbating supply. The labour and logistics required to complete the replacement of contaminated equipment, including the scheduling of outages, is another challenge to meeting the PCB deadline. Parallel to the replacement of contaminated equipment, the Company is implementing a PCB Due Diligence program to monitor equipment containing PCBs.

The *PCB Regulations* prohibit the release of more than one gram of PCB into the environment. The Company will monitor all equipment containing and suspected to contain

PCBs to ensure compliance with the release provisions of the legislation through its PCB Due Diligence program. The Company operates a number of transformers with PCB concentrations of between 10 and 31 mg/kg, and one transformer with a PCB concentration of 83mg/kg. These units comply with the regulations in effect, and will be carefully monitored for leaks and remedial action will be taken to limit PCB release. The transformer with the 83mg/kg PCB content will require action to reduce the level to below 50mg/kg for the December 31, 2025 deadline.

The PCB Mitigation Program will bring FortisBC into compliance with Environment Canada's PCB regulations. The completion of the project to identify all suspected PCB contaminated equipment will allow the Company to proceed with more certainty in 2012 - 2014. As more equipment is tested and replaced, a better understanding of the costs involved will also occur.

Table 3.3.1 (b) - PCB Environmental Compliance Forecast Expenditures

2011	2012	2013	2014
Forecast	Requested		Planned
($000s)			
2,126	11,269	11,553	4,574

3.3.2 STATION URGENT REPAIRS

The station urgent repair project is required to replace station equipment that fails in service due to severe weather, vandalism, or other unexpected reasons. The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers. The estimate for this project is based on a three year average of historical expenditure from 2008 to 2010, adjusted for inflation and changes in overheads. The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and requested expenditures for 2012 and 2013.

Table 3.3.2 - Station Urgent Repairs Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
418	599	782	639	674	818	907

3.3.3 STATION ASSESSMENTS AND MINOR PLANNED PROJECTS

This Project involves the condition assessment of the Company's 66 substations for environmental, safety and reliability issues on a ten year cycle, and completion of the work identified during these assessments in subsequent years.

The station assessments and minor planned projects address the whole substation system, which includes equipment such as transformers, breakers, batteries, and ground grids.

The work resulting from the condition assessments is planned and executed in the subsequent years as Station Minor Planned projects. Two of the programs which operate under the minor plan are the program to replace the substation backup battery system, and the program removing gap-type surge arrestors. Both programs are multi-year programs which have been approved in previous capital expenditure plans.

Table 3.3.3 - Station Assessments and Minor Planned Projects Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
2,148	1,509	286	286	708	1,343	1,354

3.3.3.1 DC Supply Replacement

A DC (direct current) system is required to operate substation protection and control equipment. The batteries supply these systems in the event of a power outage at the station, and the battery chargers supply these systems when AC (alternating current) power is available, as well as keeping the batteries fully charged. The protection and control equipment operates station breakers and switches and communicates vital information to the System Control Centre regarding the status of system alarms and transformer monitoring devices.

This project will include replacement of battery banks that meet the following criteria:

- Any gel type bank that has not been kept in a temperature controlled environment or is older than 10 years; and
- Any battery bank that tests below 80 percent of capacity as per IEEE Std 450 "Recommended Practice for Maintenance, Testing and Replacement of Vented Lead-Acid Batteries for Stationary Applications"; and

Battery banks are replaced along with the battery chargers and depending on the location, separate structures are provided for the battery rooms. Battery rooms are added in order to bring legacy substations up to current station design standards. A battery bank, charger and enclosure cost in the order of $100,000, and approximately two battery banks are replaced annually. The Company has 89 battery banks in service; replacing two banks per year gives a replacement cycle of 44 years, which exceeds the 20 year expected battery lifespan. The proposed Asset Management plan, as discussed in Section 1.1 of the Integrated System Plan - 2012 Long Term Capital Plan, will provide insight into the rate of battery bank replacement in the future.

3.3.3.2 Gap-Type Surge Arrestor Replacement Program

Surge arrestors are used to protect electrical equipment and other assets from lightning and switching surges that can damage equipment. There are two reliability issues involving gapped surge arresters; adequacy of protection and the consequential damage resulting from in service failure. Gap-Type Silicon Carbide (SiC) Surge Arresters have a higher rate of failure than Gapless Metal Oxide Varistor (MOV) arresters. Replacement of aging and failing Gap-Type Surge Arresters will provide greater protection for existing assets from lightning and switching surges. As well, because of the potential for explosive failure of surge arresters, replacing the gapped arresters will also improve work site safety. The industry trend to replace Gap-Type Surge SiC Arresters is largely due to:

- Susceptibility to moisture ingress which leads to failure; and
- Destructive failure modes, as failure of gap type surge arrestors can be accompanied by explosive destruction of the case, which is normally installed near transformer bushings.

In July 2008, lightning struck power lines near the Coffee Creek substation. The resulting surge caused the failure of one gap type surge arrester which failed violently, causing $8,000 damage to adjacent bus work. This project was first approved by Order G-11-09 in the 2009 - 2010 Capital Expenditure Plan. Material was purchased in 2010, and surge arrestor installation started in 2011, coordinating with scheduled maintenance where possible. The program will continue to install surge arrestors in 2012 and 2013.

3.3.4 ADD ARC FLASH DETECTION TO LEGACY METAL-CLAD SWITCHGEAR

FortisBC has a large number of distribution substations equipped with older, non arc-resistant metal-clad switchgear. This program is the continuation of the Arc Flash Detection relay program approved by Order G-195-10 in the 2011 Capital Expenditure Plan. This type of switchgear presents a risk of injury if a fault occurs within the switchgear when employees are inside or nearby. Arc flashes occur when a short circuit flows through air. This can result in the release of substantial amounts of energy in a very short period of time, resulting in explosive high temperature events with severe consequences to employees and equipment.

The long-term goal is to retire this type of equipment, but in the interim some measures must be taken to reduce the risk of injury where practical. The program would install arc flash detector relays in legacy metal-clad installations. These devices reduce the fault detection time, and thus exposure duration, associated with a metal-clad insulation failure. These relays would trip either the transformer high-side breaker or low-side main breaker, as applicable. The installation of these relays allows for safer working conditions for employees working near metal-clad switchgear until the legacy switch-gear can be replaced.

Table 3.3.4 (a) - Arc Flash Detection - Applicable Locations

Station (location)	Schedule
Crawford Bay	2011
Playmor (Playmor Junction)	2011
Duck Lake (Winfield)	2012
Creston	2012
Huth (Penticton)	2012
Hedley	2012
Glenmerry (Trail)	2013
Hollywood (Kelowna)	2013
Pine Street (Oliver)	2013
Joe Rich (Kelowna)	2013
Sexsmith (Kelowna)	2014
DG Bell Terminal (Kelowna)	2014
OK Mission (Kelowna)	2014
Salmo	2015
Castlegar	2015
Fruitvale	2015
Blueberry	2016
Beaver Park (Montrose)	2016
Ruckles (Grand Forks)	2016

This list identifies the sites which require mitigation. Four sites are planned for 2012 and 2013 respectively. The final six sites identified on the list have no high voltage or low voltage breaker (metal-clad protection is via high-side fuses only). These sites, starting with the Salmo substation, are not scheduled for arc flash detection relay installation until 2015 and will require the installation of a low voltage circuit breaker. These stations will be the subject of a future submission.

Stations that are planned for replacement benefit from the installation of arc flash relays through the increased safety provided. Some stations to be retrofitted with arc flash detection relays are also scheduled for future switchgear replacement in the condition-based Switchgear Replacement program (13 kV). If the switchgear replacement occurs, the arc flash detection relays will be reused at other locations. The substations in the Okanagan have relatively newer switchgear and replacement of this equipment due to condition issues is not likely to occur for many years. In the interim, the addition of arc flash relays to this legacy non-arc flash resistant switchgear will greatly improve the safety of operations while costing substantially less than a complete switchgear replacement. For example, the

Hollywood substation has 12 cells and the cost of the arc flash retrofit is estimated at $176,000 in 2013. This is substantially less than the cost of complete replacement or refitting the switchgear with arc-resistant doors. The total project is estimated to cost $4.26 million with expenditures from 2011 to 2016.

Table 3.3.4 (b) - Add Arc Flash Detection Legacy Metal-Clad Switchgear Expenditures

2011	2012	2013	2014	2015	2016
Forecast	Requested		Planned		
($000s)					
287	539	544	566	1,140	1,184

3.3.5 HUTH LOW VOLTAGE BREAKER REPLACEMENT (2 UNITS)

In April 2010 the bulk oil circuit breaker protecting the 8 kV bus at the Huth substation failed during maintenance testing, reducing reliability and decreasing operational flexibility to 8 kV supply for the City of Penticton.

The Feeder 1 breaker was manufactured in 1943 and has reached its end of life. Replacement parts are unavailable for this unit. The loss of this breaker requires the high voltage breaker to trip during fault conditions on the low voltage bus, de-energizing the 8 kV supply at the station. Frequent re-energizing of the transformers following distribution faults using the high-side breaker puts undesirable strain on the transformers.

The Feeder 2 breaker was manufactured in 1938 and is operable, but is subject to the same parts constraint as the Feeder 1 breaker. Replacing these units will also reduce the risk of oil contamination, as oil containment pits are not installed for either breaker. The replacement units will improve the reliability and operability of the 8 kV system. Both breakers would be replaced with FortisBC-standard 13 kV equipment. In the event of a voltage conversion by the City of Penticton, both breakers could be repurposed at the station or relocated.

This project is estimated to cost $0.62 million with expenditures of $0.07 million in 2013 and $0.55 million in 2014 and projected start date of 2013. The necessary in service date is 2014.

4. DISTRIBUTION

The 2012-13 Capital Plan for distribution consists of Distribution Growth projects, including New Customer Connects, as well as Distribution Sustainment projects.

New Customer Connects involves projects that provide service to new customers. The remaining projects in the Distribution Growth category are driven by general load growth that over a period of time, necessitates capacity upgrades or additions to lines in order to meet service requirements or legislated and industry standards.

The Distribution Sustainment category includes those projects necessary to rehabilitate or upgrade distribution lines in order to ensure employee and public safety, and reliable customer service.

Table 4.0 below summarizes the 2012 and 2013 expenditures for distribution projects for which FortisBC is seeking approval.

Table 4.0 - Distribution Projects

		2012	2013	Total
1	**Distribution Growth Projects**		**($000s)**	
2	New Connects System Wide	11,057	10,780	21,837
3	Small Growth Projects	1,069	888	1,957
4	Distribution Unplanned Growth	924	930	1,854
5	Glenmerry Feeder 2-Glenmerry Feeder 1 Tie Line	596	-	596
6	Ellison Feeder 2 to Sexsmith Feeder 1 Tie	-	1,161	1,161
7	**Total Distribution Growth**	**13,646**	**13,759**	**27,405**
8				
9	**Distribution Sustainment Projects**			
10	Distribution Urgent Repairs	2,411	2,315	4,726
11	Distribution Line Condition Assessment	1,410	1,398	2,808
12	Distribution Line Rehabilitation	5,298	3,517	8,815
13	Distribution Line Rebuilds	1,679	1,660	3,339
14	Distribution Line Small Planned Capital	726	826	1,552
15	Forced Upgrades and Lines Moves	2,012	2,413	4,425
16	41 Line Salvage and Distribution Underbuild Rehabilitation	2,067	-	2,067
17	**Total Distribution Sustainment**	**15,603**	**12,129**	**27,732**
18	**Total Distribution Projects**	**29,249**	**25,889**	**55,137**

4.1 Distribution Growth Projects

4.1.1 Distribution Line New Connects System Wide

This project involves the installation of new electric services consisting of additions to FortisBC overhead and underground distribution facilities. These capital expenditures allow FortisBC to meet its obligation to provide reliable service to customers in the service area. This project will also fund any forced upgrade costs associated with upgrading FortisBC facilities to provide service for an extension or drop service.

In 2009, FortisBC submitted a Cost of Service Analysis (COSA) and Rate Design Application (RDA) to the Commission that outlined a new methodology for calculating the amount that the Company would contribute towards the construction of a customer extension. Prior to this revised methodology, Rate Schedule 74 of the electrical tariff outlined the Company's contribution towards an extension as consisting of the transformer, drop service and meter. The revised methodology proposed as part of the RDA, and since approved by the Commission, provides customers a capital credit or allowance based on amount of investment in distribution poles, conductors, and transformers for the rate classes covered in the applicable retail rate. Any investment in poles, conductors and transformers necessary to provide service to a customer in excess of this credit or allowance will be paid as a capital contribution by the new customer.

The expenditures shown in Table 4.1.1 are derived based on a three-year rolling average adjusted for anomalous years (2008), projected customer growth, inflation and changes to overhead loading. The three-year rolling average method is used to derive this budget as FortisBC cannot foresee the range of dynamic variables in the future that would affect this budget. Using historical spending patterns to predict the basis of upcoming years' budgets is the most logical approach from FortisBC's perspective. The following table shows the actual expenditures for new connects, net of customer contributions, for the years 2007 to 2010, the forecast for 2011 and requested expenditures for 2012-2013.

Table 4.1.1 - Distribution Line New Connects System Wide Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
8,861	12,845	8,782	8,660	8,758	11,057	10,780

4.1.2 DISTRIBUTION LINE SMALL GROWTH

Small Growth Projects relate to capacity upgrades, feeder ties, and load transfers. These projects are required to keep pace with normal load growth on the distribution system and to ensure acceptable standards of service are maintained. These service standards include operation of facilities at or below normal continuous thermal limits, maintaining voltage consistent with Canadian Standards Association (CSA) recommended levels, and ensuring short circuit levels are adequate for safe operation of the electrical system. Capacity increases must also be designed to provide sufficient redundancy to maintain supply during planned and unplanned outages on the distribution system. The Small Growth Projects are defined by a distribution capacity related upgrade under $500,000.

The following projects fit the above criteria and were created as a result of a detailed load study analysis performed by an external consultant using power simulation software and current distribution load forecast values.

Small Growth projects have estimated expenditures of $1.07 million in 2012 and $0.89 million in 2013.

4.1.2.1 DG Bell Feeder 1 and Feeder 2 Upgrades (2012)

DG Bell Feeder 2 is heavily loaded, and there are some large developments proposed in the area which will overload the feeder in the near future. The construction of the Benvoulin substation in 2010 resulted in a large load transfer off of DG Bell Feeder 1 and created concerns in contingency situations. This project is required to reconfigure the DG Bell Feeders 1 and 2 in order to balance load between them and ensure each feeder is able to back the other one up.

4.1.2.2 Hollywood Feeder 2 and Feeder 3 Offload (2012)

Hollywood feeders 2 and 3 are currently heavily loaded and are forecast to continue to experience steady growth. The construction of the Benvoulin substation in 2010 resulted in a large load transfer off Hollywood Feeder 7 onto Benvoulin Feeder 2. This project is required to reconfigure Hollywood Feeders 2, 3 and 7 in order to balance load between them and to defer the need for more costly capacity upgrades.

4.1.2.3 OK Mission Feeder 5 Offload (2012)

The 2005 SDP included a project to extend OK Mission Feeder 5 to relieve the overloaded OK Mission Feeder 4 and Glenmore Feeder 1. With the construction of the Benvoulin substation in 2010 and the load growth experienced on the OK Mission feeder, this project is required to transfer load onto one of the new Benvoulin feeders.

4.1.2.4 Ellison Feeder 4 Regulators (2012)

Over the past few years there has been load growth in the McKinley Landing area in north Kelowna. There are also large development plans from the local irrigation district in future years. The current 50 Amp regulator bank that sources the north end of this feeder has reached its capacity and is near its end of life. This project is required to upgrade the regulator with a larger capacity unit and relocate it in order to provide operating flexibility between this Ellison feeder and the old Sexsmith feeder.

4.1.2.5 Princeton Feeder 4 Regulators (2013)

The Princeton Feeder 4 circuit has two long radial taps that extend several kilometres north of the town. One of the radial taps has already been converted to 25 kV in order to minimize voltage losses. Based on the load forecast for the area, the other radial tap is expected to experience low voltage during peak demand. This project defers the higher costs associated with a 25 kV conversion and is required to ensure that the voltage is maintained within CSA recommended levels.

4.1.2.6 Princeton Feeder 2 Regulators (2013)

Princeton Feeder 2 has a long radial tap that extends several kilometres west of the town. Based on the load forecast for the area, there are areas along this tap that are expected to experience low voltage during peak demand periods. This project defers the higher costs associated with a 25 kV conversion and is required to ensure the voltage is maintained within CSA recommended levels.

4.1.2.7 Glenmore Feeder 6 Upgrade (2013)

Glenmore Feeder 6 currently serves the North Glenmore area. The main line is located along Clifton Road and serves major subdivisions such as Magic Estates and Sheerwater and the fast growing Wilden subdivision. This project involves the upgrading of conductor along Clifton Road and is required to provide sufficient capacity for future projected load growth in the North Glenmore area.

4.1.3 DISTRIBUTION LINE UNPLANNED GROWTH

Capacity upgrades and line extensions are required periodically to keep pace with normal load growth on the distribution system and to ensure acceptable standards of service are maintained. These service standards include operation of facilities at or below normal continuous thermal limits, maintaining voltage consistent with CSA recommended levels, and ensuring short circuit levels are adequate for safe operation of the electrical system. Capacity increases must also be designed to provide sufficient redundancy to maintain supply during planned and unplanned outages on the distribution system.

Experience has shown that unforeseen load emergence will require capacity upgrades and voltage correction projects not specifically identified in the capital planning process. The projects typically include service upgrades, voltage regulation, ties to accommodate load splitting, single phase to three phase upgrades and conductor upgrades. Also included is the interconnection of feeders to permit load transfers. As the distribution load grows in different areas, feeder loading becomes unbalanced; the interconnection of feeders allows FortisBC to optimize loading. This project is required to provide for such items that were unforeseen at the time the expenditure plan was prepared.

The estimates are based on a three year rolling average of historical expenditures from 2008 to 2010, adjusted for inflation and changes in overhead loading. The three-year rolling average method is used to derive this budget as FortisBC cannot foresee the range of dynamic variables in the future that would affect this budget. Using historical spending patterns to predict the basis of upcoming years' budgets is the most logical approach from FortisBC's perspective. The following table shows the actual expenditures for the unplanned growth project for the years 2007 to 2010 as well as the forecast for 2011 and plan for 2012-2013.

Table 4.1.3 - Distribution Line Unplanned Growth Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
1,065	834	604	750	986	924	930

4.1.4 Glenmerry Feeder 2 To Glenmerry Feeder 1 Tie Line

Glenmerry Feeder 1 is a short, lightly loaded feeder that supplies the community of Casino near Trail. It has 1.8 kilometres of three-phase line and at the 1.6 kilometre mark has a 5.5 kilometre single-phase tap. With a forecast 2011 winter peak of 0.281 MVA this feeder is under-used and not operating in an optimum configuration.

Fruitvale substation Transformer 1 is currently exceeding the nameplate capacity rating during peak load conditions. In order to alleviate this overload, a 2010 project transferred load from Fruitvale Feeder 1 onto Beaver Park Feeder 2, and also transferred load from Beaver Park Feeder 1 to Glenmerry Feeder 2. As well, during 2010, customer load connected to Beaver Park Feeder 2 drove Beaver Park Transformer 1 into an overloaded condition. Load transferred between Beaver Park Feeder 1 and Glenmerry Feeder 2 will allow Beaver Park Transformer 1 to operate below its nameplate rating, however the transfer will cause Glenmerry Feeder 2 to operate outside of its normal rated limits (400A).

This project involves the construction of a river crossing to extend Glenmerry Feeder 1 across the Columbia River to tie into Glenmerry Feeder 2 and allow load transfer between the two Glenmerry feeders, as shown in Figures 4.1.4 (a) and (b) below.

Figure 4.1.4 (a) - Glenmerry Feeder Orientation Before

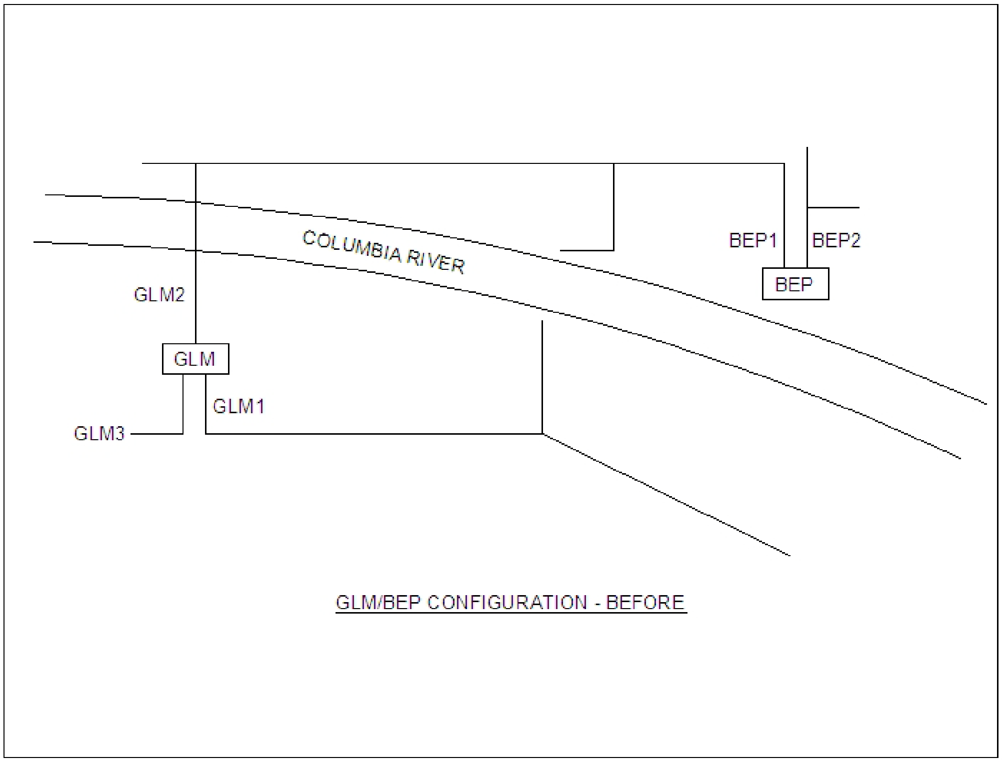
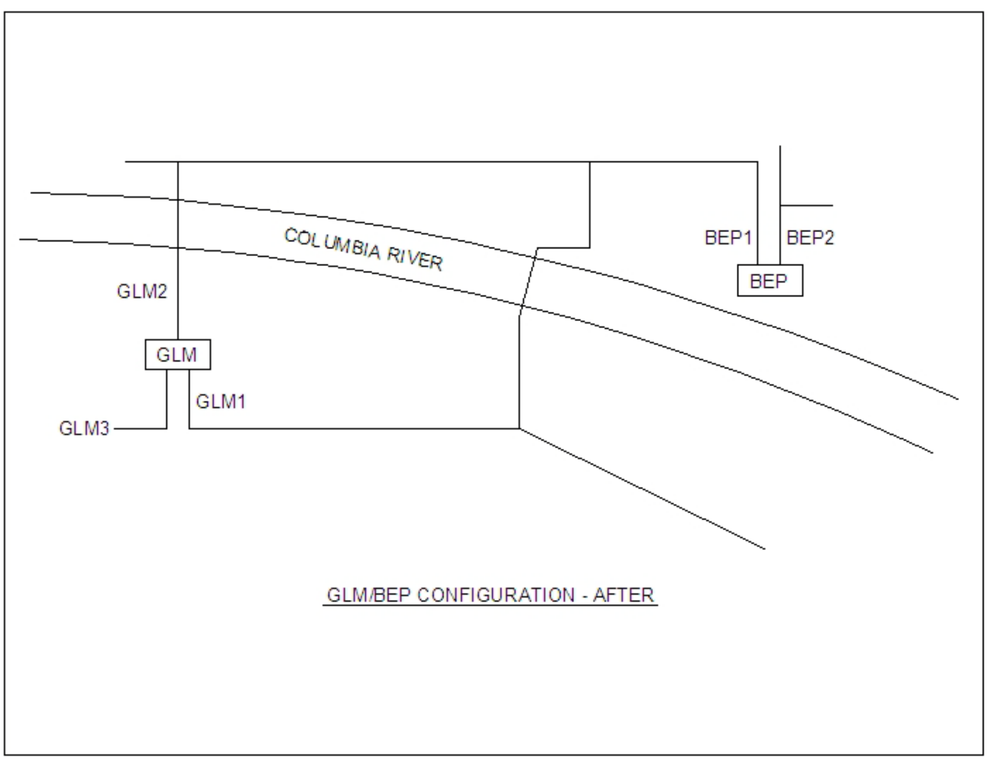


Figure 4.1.4 (b) - Glenmerry Feeder Orientation After



This project will offload Glenmerry Feeder 2 and Beaver Park Feeder 1 and in turn reduce enough load off Beaver Park Transformer 1 to defer the need for a major capacity increase project another 8 to 10 years. The alternative option to completing this project is to upgrade Beaver Park immediately and Fruitvale within 8 to 10 years in order to resolve capacity requirements.

This project is estimated to cost $0.60 million in 2012.

4.1.5 ELLISON FEEDER 2 TO SEXSMITH FEEDER 1 TIE

Ellison Feeder 2 will tie in and offload a significant portion of Sexsmith Feeder 1 by re-conductoring the main trunk line along Old Vernon Road. Sexsmith T1 transformer is currently forecast to exceed its rated summer capacity of 31.5 MVA in 2015. This project will offload sufficient load from Sexsmith T1 transformer so that installing an additional transformer at Sexsmith can be deferred until beyond 2020.

Another benefit of this project is the operational flexibility it provides between the FA Lee and Ellison stations. FA Lee Feeder 1 is one of the most heavily loaded feeders in the FortisBC service territory and is currently forecast to reach 15 MVA in 2013. Plans are currently in place to offload approximately 1.5 MVA into Black Mountain substation and with this project a further reduction of 1.3 MVA of load would reduce the peak for FA Lee Feeder 1 to approximately 12 MVA.

This project is estimated to cost $1.16 million in 2013 as derived from engineered estimates.

4.2 Distribution Sustainment Programs and Projects

The distribution sustainment projects are for rehabilitation and ongoing upgrades of the distribution system to ensure safe, reliable service.

Table 4.2 - Distribution Sustainment Programs and Projects

		2012	2013	Total
	Distribution Sustainment Projects	**($000s)**		
1	Distribution Urgent Repairs	2,411	2,315	4,726
2	Distribution Line Condition Assessment	1,410	1,398	2,808
3	Distribution Line Rehabilitation	5,298	3,517	8,815
4	Distribution Line Rebuilds	1,679	1,660	3,339
5	Distribution Line Small Planned Capital	726	826	1,552
6	Forced Upgrades and Lines Moves	2,012	2,413	4,425
7	41 Line Salvage and Distribution Underbuild Rehabilitation	2,067	-	2,067
8	**Total Distribution Sustainment**	**15,603**	**12,130**	**27,733**

4.2.1 DISTRIBUTION URGENT REPAIRS

Component failures or components that are in poor condition and in danger of immediate failure on the distribution system, resulting from factors such as weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, or vehicle collisions, can cause outages or present risks that must be addressed in an expedient manner.

This program is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

The planned expenditures for this program are based on a three-year rolling average of historical expenditures from 2008 to 2010, adjusted for inflation and changes to overhead loadings. The three-year rolling average method is used to derive this budget as FortisBC cannot foresee the range of dynamic variables in the future that would affect this budget. Using historical spending patterns to predict the basis of upcoming years' budgets is the most logical approach from FortisBC's perspective. The following table shows the actual expenditures for the years 2007 to 2010 as well as forecast for 2011 and plan for 2012-2013.

Table 4.2.1 - Distribution Urgent Repairs Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
2,117	3,258	2,370	2,008	2,842	2,411	2,315

4.2.2 DISTRIBUTION LINE CONDITION ASSESSMENT

The distribution system requires a proactive program to manage the risk to employee and public safety, and to ensure an acceptable level of service is met.

The distribution line condition assessment program is based on an eight-year cycle of inspecting and testing all FortisBC distribution line facilities in order to extend the life of the pole and ensure the integrity of the lines. The program consists of a test and treat component and an above ground visual condition inspection. The test and treat component of the program is aimed at the section of pole at the ground level and below and consists of drilling test holes in each pole to identify internal rot and adding pole treatment into the hole to reduce internal rot. The above ground visual inspection focuses on the condition of the pole itself and all equipment (anchoring, cross-arms, insulators, guying and grounding). In underground systems, the distribution line condition assessment consists of visually inspecting all accessible underground facilities for overall condition (connector heat scanning, corrosion, moisture, vegetation, rodents, etc.). If an issue is detected during the condition assessment the deficiency is documented and corrected the following year under the distribution line rehabilitation budget. Please also refer to Appendix I to FortisBC's 2012 Long Term Capital Plan which provides further detail on the conduct of condition assessments and identification of deficiencies for the distribution system.

Tables 4.2.2 (a) and (b) below show the distribution lines scheduled for assessment in 2012 and 2013. Table 4.2.2 (c) shows the expenditures for the distribution line condition assessment project for the years 2007 to 2010 as well as the forecast amount for 2011 and the requested amounts for 2012 and 2013. The estimates for 2012 and 2013 are derived by applying a total cost required to assess the structure (based on historical information and contractual agreements) to the number of distribution poles being assessed. This number is then adjusted for inflation and overhead loading.

Table 4.2.2 (a) - 2012 Distribution Line Condition Assessment Projects

Area	Substation/Feeder	Poles
Kootenay	Castlegar Feeder 1	631
Kootenay	Coffee Creek Feeder 1	429
Kootenay	Glenmerry Feeder 2	791
Kootenay	Kaslo Feeder 1	398
Kootenay	Kettle Valley Feeder 1	2,557
Kootenay	Kettle Valley Feeder 6	426
Kootenay	Midway Step Down Feeder 2	528
North Okanagan	DG Bell Feeder 1	2,054
North Okanagan	Glenmore Feeder 1, Feeder 2 and Feeder 7	1,342
North Okanagan	OK Mission Feeder 4	263
South Okanagan	Arawana Feeder 2	802
South Okanagan	Hedley Feeder 2, Feeder 3 and Feeder 4	1,236
South Okanagan	RG Anderson Terminal Feeder 1	286
South Okanagan	Trout Creek Feeder 1	26
	Total	**11,769**

Table 4.2.2 (b) - 2013 Distribution Line Condition Assessment Projects

Area	Substation/Feeder	Poles
Kootenay	Creston Feeder 3	470
Kootenay	Cascade Feeder 2 and Feeder 3	1,433
Kootenay	Fruitvale Feeder 2	102
Kootenay	Grand Forks Terminal Feeder 1	2,713
Kootenay	Glenmerry Feeder 1 and Feeder 3	584
Kootenay	Hearns Feeder 1	388
Kootenay	Kaslo Feeder 2	658
North Okanagan	DG Bell Feeder 3	847
North Okanagan	Glenmore Feeder 5	1,242
South Okanagan	Princeton Feeder 4 (NOR1)	3,052
South Okanagan	OK Falls Feeder 1	628
South Okanagan	West Bench Feeder 1	461
	Total	**12,578**

Table 4.2.2 (c) - Distribution Line Condition Assessment Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				**Forecast**	**Requested**	
($000s)						
938	692	659	605	992	1,410	1,398

4.2.3 DISTRIBUTION LINE REHABILITATION

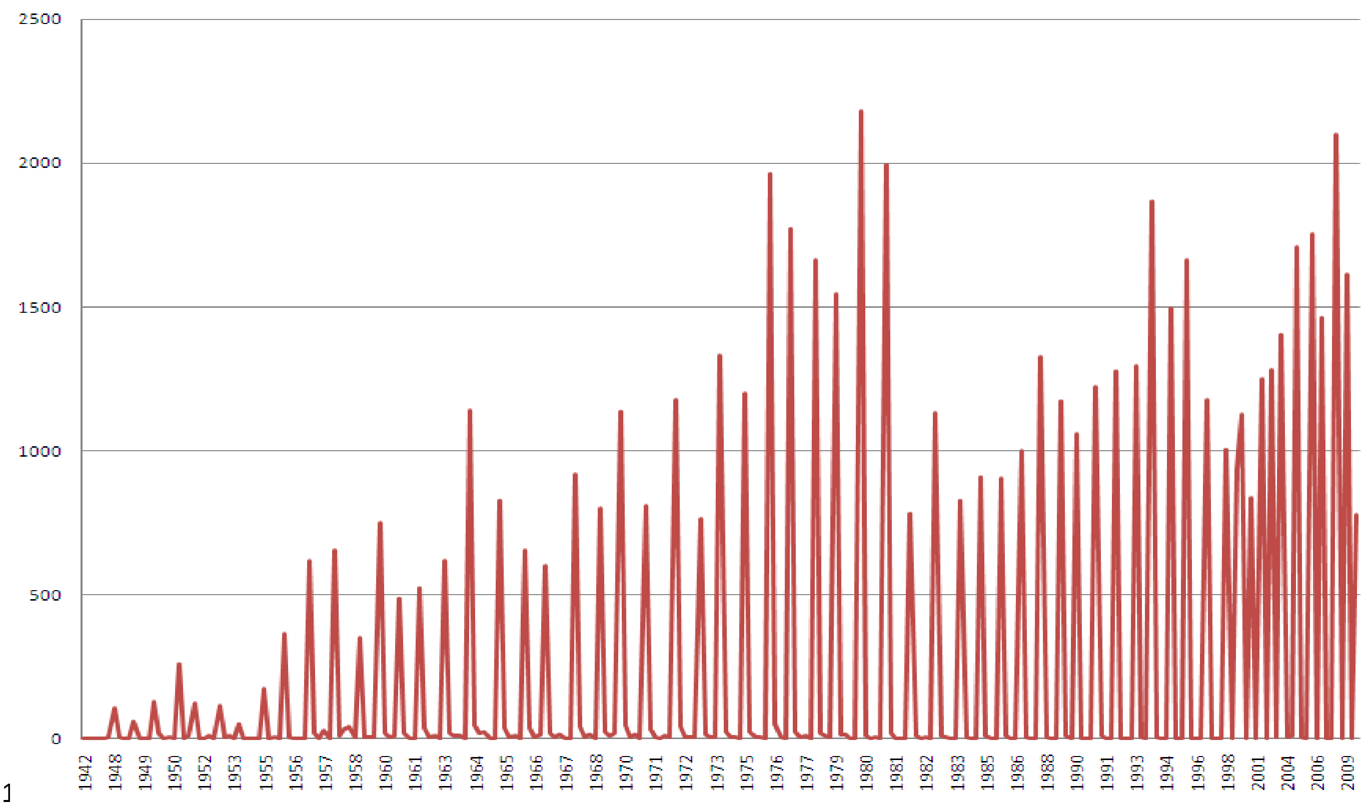
Rehabilitation work for the various distribution lines involves expenditures for stubbing poles, replacing poles, cross-arms, insulators, guy wires, and correcting other defects identified through the previous year's Distribution Condition Assessment program. The Rehabilitation program deals with issues that, while not severe enough to require immediate repairs (in which case they would be carried out immediately under the Distribution Urgent Repairs program), are serious enough that they must be addressed in the year following the Condition Assessment. These corrective actions are necessary to maintain safe and reliable operation of the distribution system. In 2012 and 2013, the Company will undertake any necessary rehabilitation of the distribution lines assessed in 2011 and 2012 respectively. The following table outlines the feeders being rehabilitated in 2012, with the feeders identified in Table 4.2.2 (a) above scheduled to be rehabilitated in 2013.

Table 4.2.3 (a) - 2012 Distribution Rehabilitation Feeders

Area	Substation/Feeder	Poles
Area	**Substation/Feeder**	**Poles**
Kootenay	Creston Feeder 1	1,526
Kootenay	Lambert Feeder 3	403
Kootenay	Blueberry Feeder 1	378
Kootenay	Ruckles Feeder 5	845
Kootenay	Fruitvale Feeder 1	1,250
Kootenay	Beaver Park Feeder 1	372
Kootenay	Beaver Park Feeder 2	714
Kootenay	Cascade Feeder 1	320
North Okanagan	Big White Feeder 1	241
North Okanagan	Big White Feeder 2	243
North Okanagan	Big White Feeder 3	109
North Okanagan	Hollywood Feeder 2	583
North Okanagan	Hollywood Feeder 4	611
North Okanagan	Hollywood Feeder 5	880
North Okanagan	Hollywood Feeder 7	798
North Okanagan	Joe Rich Feeder 1	1,084
South Okanagan	Keremeos Feeder 1	1,727
South Okanagan	Oliver Feeder 1	1,214
South Okanagan	Oliver Feeder 2	732
South Okanagan	Arawana Feeder 1	391
South Okanagan	Princeton Feeder 4	1,299
	Total	**15,720**

FortisBC has approximately 140 distribution feeders consisting of approximately 5,500 kilometres of line and 87,000 poles. Approximately 60 percent of these poles are in excess of 30 years old and approximately 40 percent of the poles are over 40 years old. Given that the life expectancy of a wooden distribution pole is approximately 30-40 years, based on pole demographics and historical experience, rehabilitation program expenditures will need to increase in order to accommodate the large quantity of poles that will need to be replaced within the near future. Figure 4.2.3 below is a graph that outlines the quantity of distribution poles in operation versus the vintage of the poles. The graph illustrates the large population of poles in the system that are 30-40 years old.

Figure 4.2.3 - Distribution Poles vs Pole Vintage



The proposed increase in rehabilitation expenditures for 2012/13 is required due:

- The increased number of poles which are scheduled to be assessed in 2011 and thus require rehabilitation in the following year;
- Work which was carried over to 2012 from 2011 (unable to be completed due to 2011 budget constraints); and

- Increases in construction costs (due to labour inflation, material costs, and corporate loading increases).

It should be noted that at the time of filing this 2012-13 Capital Plan, the Condition Assessment program for 2011 is still underway and thus pole test results and condition reports are not yet available. On that basis, the forecast expenditures are based on previous years actual costs combined with knowledge of the areas being assessed and the expected condition of the equipment.

The following table shows the actual expenditures for the distribution line rehabilitation program for the years 2007 to 2010 as well as the forecast amount for 2011 and requested expenditures for 2012 and 2013.

Table 4.2.3 (b) - Distribution Line Rehabilitation Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
1,375	3,727	3,294	3,086	2,303	5,298	3,517

4.2.4 Distribution Line Rebuilds

This project involves the replacement of aged and/or deteriorated equipment. Items include rebuilding failing overhead and underground conductor, replacement if rotted poles and platforms, replacement of leaking transformers, installation of ground grids at ungrounded services, and the replacement of copper conductor in areas considered to be a risk to public or employee safety. These deficiencies were identified through condition assessment data, site assessments and normal daily operations. This project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and requested expenditures for 2012 and 2013 which are based on engineered estimates.

Table 4.2.4 - Distribution Line Rebuilds Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
1,528	1,310	1,371	1,240	2,071	1,679	1,660

4.2.5 SMALL PLANNED CAPITAL

This program is similar to the Distribution Condition Assessment and Rehabilitation programs but captures off-cycle work required to keep the distribution lines safe and reliable. Each year operational and safety concerns on the distribution system including storm damage, clearance problems and aging equipment, are identified by field staff outside of the normal assessment cycle. Repairs to address these concerns are required to maintain a safe and reliable distribution system. The repairs are generally non-urgent in nature and consequently are not completed under the distribution urgent repair program. They are normally completed within one year of the initial request.

The planned expenditures for this project are based on a three-year rolling average of historical expenditures from 2008 to 2010, adjusted for inflation and changes to overhead loading. The three- year rolling average method is used to derive this budget as FortisBC cannot foresee the range of dynamic variables in the future that would affect this budget. Using historical spending patterns to predict the basis of upcoming years' budgets is the most logical approach from FortisBC's perspective. The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and plan for 2012 and 2013.

Table 4.2.5 - Small Planned Capital

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
1,080	572	642	868	805	726	826

4.2.6 FORCED UPGRADES AND LINE MOVES

This program is required to complete distribution upgrades driven by third party requests. Relocation of distribution lines due to highway/road widening or improvements will be initiated based on requests from the BC Ministry of Transportation and/or municipalities. Miscellaneous customer line move requests where FortisBC does not have sufficient land rights for existing facilities located on customer property are also included in this program.

The planned expenditures for this program are based on a three year rolling average of historical expenditures from 2008 to 2010, adjusted for inflation and changes to overhead loading. The three-year rolling average method is used to derive this budget as FortisBC cannot foresee the range of dynamic variables in the future that would affect this budget. Using historical spending patterns to predict the basis of upcoming years' budgets is the most logical approach from FortisBC's perspective. The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and requested expenditures for 2012 and 2013.

Table 4.2.6 - Forced Upgrades and Line Moves Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
1,573	385	2,016	3,768	1,572	2,012	2,413

4.2.7 41 Line Salvage and Distribution Underbuild Rehabilitation

With the completion of the OTR project, 41 Line is no longer required to provide transmission service. Originally constructed in 1921, many of the 41 Line structures are in poor and deteriorated condition and will require rehabilitation. A condition assessment performed in 2010 identified approximately $850,000 of necessary rehabilitation work.

Based on the expenditures required to rehabilitate the line and continue to maintain it, the Company is proposing to salvage a portion of the 41 Line transmission conductor and structures that do not have distribution underbuild along the full right of way while converting the remaining sections with distribution underbuild to a standalone distribution feeder (no transmission overbuild).There is a small section of 41 Line, less than 10 percent of the line length, that will remain to be reused as a distribution feeder tie between the Kaleden substation and the OK Falls substation. Currently there is no backup capability to the Kaleden feeder as it operates radially. This project will enable the offload of the Kaleden station to the OK Falls station in the event of a distribution contingency, resulting in improved reliability to customers served by the Kaleden feeder.

FortisBC estimates that the copper conductor to be removed has a salvage value between $200,000 and $300,000, however due to the uncertainty of this estimate, this value has not been applied as a credit to the cost of the project at this time but will be reflected in the actual costs of removal incurred.

This project is estimated to cost $2.07 million in 2012.

5. TELECOMMUNICATIONS, SCADA PROTECTION AND CONTROL

FortisBC owns, maintains and operates an extensive communications network in support of the safe, reliable and efficient operation of the electric grid in the Company's service area. 106 locations including 59 distribution, 11 generation, 12 transmission, and six office locations are connected to the network. Communication links are also provided between neighbouring utilities such as BC Hydro, Columbia Power Corporation and Bonneville Power Administration for exchange of operational data and protection circuits.

A variety of telecommunications transport systems are used, depending on technical requirements, economics, and system reliability requirements. These include powerline carrier, fibre-optic cable, copper pairs, third-party leased lines, cellular voice/data, and radio (VHF, microwave, spread spectrum and packet radio). The telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. It also provides a low-cost alternative to the public network for internal business data and some voice traffic. Forecast expenditures for 2012 and 2013 are shown in Table 5.0 below.

Table 5.0 - Telecommunications, SCADA, Protection and Control Projects

		2012	2013	Total
1	**Telecom SCADA Protection and Control Growth**		**($000s)**	
2	Kelowna 138 kV Loop Fibre Installation	1,212	2,549	3,761
3	**Total Telecom SCADA Protection and Control Growth**	**1,212**	**2,549**	**3,761**
4				
5	**Telecom SCADA Protection and Control Sustainment**			
6	Communication Upgrades	410	400	810
7	SCADA Systems Sustainment	707	733	1,440
8	**Total Telecom SCADA Protection and Control Sustainment**	**1,117**	**1,133**	**2,250**
9	**Total Telecom SCADA Protection and Control Projects**	**2,329**	**3,682**	**6,011**

5.1 Telecommunications, SCADA, Protection and Control Growth Projects

5.1.1 KELOWNA 138 KV LOOP FIBRE INSTALLATION

This project is a multiple-year effort to improve the capacity and reliability of the communications infrastructure in the Kelowna area and will lay the groundwork for future power system reliability improvements. The project includes the installation of multi-strand single-mode fibre cable which will supplement existing fibre leased under a long-term Indefeasible Right of Use (IRU) and existing FortisBC-owned fibre optic cabling. This will complete a physical fibre-optic ring to all Kelowna area substations. In addition, high speed digital multiplexers will be installed at these substations to take advantage of this new fibre and facilitate high speed, reliable communications in the area, including the future ability to fully mesh substation protection systems.

FortisBC has recently reached a settlement that secures reasonably priced, long term access to fibre in the area; therefore, there are no additional capital costs to this project for use of this fibre. The proposed build would allow FortisBC to fully leverage this existing fibre that FortisBC now has access to by completing gaps in the third party's network, and thus completing a physical fibre loop to all Kelowna-area substations. This enhances the reliability of communications in the area and makes possible the delivery of robust services to all locations. Without this additional fibre construction, FortisBC will be unable to take full advantage of the leased fibre and three major distribution substations in central Kelowna will not be able to be connected to the fibre network.

This project was originally proposed in the FortisBC 2011 Capital Expenditure Plan. In its Reasons for Decision accompanying Order G-195-10, the Commission requested that a CPCN be filed for the project on the basis that:

> *"The Commission Panel is not satisfied that the information provided in this Application in support of the two projects is sufficient to justify acceptance at this time. Nor is the Commission Panel satisfied that all reasonable alternatives have been adequately reviewed and appropriately costed, as the estimates put forward were general with wide margins of error. The Commission Panel further finds that this infrastructure has significant excess capacity which has not been adequately identified. Furthermore, opportunities for its potential utilization have not been sufficiently explored.*
>
> *The Commission Panel further specifically rejects the notion of a corporate policy prohibiting the use of third party communications infrastructure as being a reasonable factor for inclusion in a review of the cost-effectiveness of the two projects. The Commission Panel is of the view that the public interest requires a proper, detailed examination of alternatives involving the use of third party providers and/or potential joint venture partners." [Order G-195-10, page 40]*

Subsequent to the previous 2011 Capital Plan submission and in order to address the Commission's concerns regarding the accuracy of the estimates, FortisBC has refined the level of accuracy for the project costs. Cost estimates for the recommended option are considered to be approximately AACE Class 3 for the majority of the work with some portions at a Class 4 level due to the detailed fibre routing for some sections not being fully defined at this time. At the time of original submission, the proposal was for FortisBC to build the entire 33 kilometre length of new fibre, which is significantly more expensive than the currently proposed option, which involves leasing via an IRU the majority of fibre facilities as described above.

Furthermore, with respect to the Commission's concerns regarding FortisBC's policy restricting the use of third- party communications facilities to carry tele-protection traffic, the Company would like to clarify this position, and draw attention to the difference between third party "infrastructure" and third party "circuits".

- "Infrastructure" in this context is considered physical media such as dark fibre optic cable and coaxial or twisted pair copper cable. FortisBC would control the electronic equipment on either end of this physical media.
- "Circuits" in this context are assumed to be leased services provided by a third party, where FortisBC does not have control or knowledge of the intermediary electronic devices and their associated security, access control, power supplies and/or equipment type.
- FortisBC does not have an issue using third party infrastructure to carry critical traffic presuming that sufficient steps are taken to address reliability and security concerns arising from potential access to the infrastructure.
- FortisBC's practice of only using utility-owned and controlled circuits for protection traffic is in accordance with utility industry guidelines set out in Western Electricity Coordinating Council (WECC) documents. These guidelines preclude the use of leased circuits from being the primary carrier of critical traffic, including protection, but permit their use for redundancy and increasing overall circuit availability.

FortisBC believes that the decreased scope and cost of the new proposed project combined with the further delineation of the alternative option costs and the inclusion of a third party leased option sufficiently addresses the Commissions' concerns. On that basis, FortisBC is requesting approval of the requested expenditures related to the proposed project as submitted in the 2012-13 Capital Plan.

Options Analysis

It must be recognized that the existing 900 MHz wireless communications system in Kelowna has reached end-of-life and requires replacement in order to maintain existing service levels. On that basis, the "Do Nothing" option is not applicable as the system will eventually fail and repair parts are no longer available. The current system provides primary communications to Sexsmith, Hollywood, Glenmore, Recreation, Saucier, OK Mission and Benvoulin Substations.

FortisBC examined several different alternatives to replace this existing point-to-multipoint wireless system before determining that the construction of a fibre-based communications network best served the long term customer needs. These included the following options:

- Replacing the existing equipment with similar devices of modern vintage;
- Replacing with power-line carrier equipment;
- Replacing with microwave point-to-point wireless communications;
- Replacing with leased communications from a telecommunication service provider;
- Replacing with fibre-optic cable and multiplexing equipment in a point-to-point configuration; or
- Replacing with fibre-optic cable and multiplexing equipment in a ring configuration.

A detailed examination of the pros and cons and financial cost/benefits follows. It should be noted that for this discussion, only the installation of fibre infrastructure and multiplexers have been specifically considered in the justification. The need and any justification for the incremental power system reliability enhancements provided by future protection additions and enhancements will be developed and presented in a subsequent application. The outcome of this future application does not affect the justification for the currently proposed project as there is sufficient information to justify the project on a standalone basis. Notwithstanding this, the capability to support future reliability enhancements was given weight when choosing the preferred option.

For these combined cost/benefit and options analysis the following assumptions were used:

- Estimates are AACE Class 3 for the majority of the work with some portions at a Class 4 level due to the detailed fibre routing for some sections not being fully defined at this time.
- The system availability of the existing FortisBC-owned wireless communications network is approximately 99.5% (e.g. the system is unavailable for approximately 2 days per year) and decreasing as the equipment continues to age and failures become more frequent. The system availability of third-party leased communications

services is approximately 99.5% (e.g. the system is unavailable for approximately 2 days per year);

- The system availability of new communications systems is assumed to be:
    - 99.9% for wireless point-to-multipoint, leased line
    - 99.95% for microwave point-to-point and redundant PLC
    - 99.99% for point-to-point fibre based solution
    - 99.999% for ring configuration fibre based solution
- The customer cost of interruption resulting from a one hour outage to all Kelowna load is estimated at approximately $5 million. This figure represents the costs to customers due to an extended supply outage (such as lost production, business disruption, societal impact, etc.); it is not simply the value of unsupplied electricity service by the utility.

Based on historical performance, failures of the currently installed communications system has previously impacted and will continue to threaten the ability to remotely restore the power system following a transmission outage. As a result, what could be a short-duration outage (less than 5 minutes) instead results in an extended outage. On average, it is expected that this will result in an additional one hour outage affecting approximately 100 MW of load every 2 years.

Thus, on average, FortisBC estimates that failures of the existing communications system results in interruption costs to customers in Kelowna representing approximately $1 million per year (on average). In other words, if the Kelowna communications system was replaced with equipment that could be considered near fully available, then communications failures would have no negative impact on the duration of power system outages. Customer outages would still occur, however they would not be unnecessarily extended by failures of the communications system. Elimination of this impact on reliability would thus represent a savings to customers of approximately $1 million per year through reduced outage impacts as seen in options B, C, E, and F below. This $1 million figure represents the societal costs to customers due to an extended supply outage (such as lost production, business disruption, or societal impact). It is not simply the value of unsupplied electricity service by the utility nor does it represent an avoided cost to FortisBC.

Option A: Replace the existing Kelowna wireless system with similar equipment of modern vintage.

Pros:

- Provides basic communications functionality for SCADA remote control; and
- No dependence on third-parties for operational communications

Cons:

- No system capacity for future upgrades to support inter-station protection (unable to provide full N-1 transmission reliability for over 250 MW of load);
- No system capacity for future Smart Grid initiatives (AMI, etc.);
- Requires relocation of existing mountain-top repeater site to reduce undesirable system interference;
- Dependent on mountain-top repeater equipment which is difficult and expensive to access and maintain, especially during the winter;
- Lower reliability due to minimal equipment redundancy (approximately 99.9% system availability); and
- Third-party leased services still required for corporate WAN communications

Costs:

- Capital Costs - $1.81 million; and
- Ongoing leased communications for corporate WAN: $0.06 million per year

Benefits:

- Reduced outage duration costs to customers: $0.2 million per year

Option B: Replace the existing Kelowna wireless system with power-line carrier equipment.

Pros:

- Provides basic communications functionality for SCADA remote control;
- Provides basic tele-protection communications between substations to support future meshing of transmission system;
- All communications equipment would be located in existing substation sites; and
- No dependence on third-parties for operational communications.

Cons:

- No system capacity for future Smart Grid initiatives (AMI, etc.);
- Power-line carrier is considered somewhat outmoded technology by many utilities due to its low system capacity compared to other communications technologies; and
- Third-party leased services still required for corporate WAN communications.

Costs:

- Capital Costs - $5.45 million; and
- Ongoing leased communications for corporate WAN: $0.06 million per year

Benefits:

- Reduced outage duration costs: $1 million per year (for communications upgrade only - additional future savings would be possible by meshing the transmission system).

Option C: Replace the existing Kelowna wireless system with point-to-point wireless communications.

Pros:

- Provides communications functionality for SCADA remote control;
- Provides tele-protection communications between substations to support future meshing of transmission system;
- All communications equipment would be located in existing substation sites;
- Increased reliability due to redundant equipment installation (approximately 99.95% system availability);
- No dependence on third-parties for operational communications; and
- System capacity for future upgrades to support Smart Grid initiatives (AMI, etc.).

Cons:

- Constrained system capacity for future upgrades to support Smart Grid initiatives (AMI, etc.);
- Could be technically infeasible if line-of-sight is not available between all locations; and
- Third-party leased services still required for corporate WAN communications.

Costs:

- Capital Costs - $6.2 million
- Ongoing leased communications for corporate WAN: $0.06 million per year

Benefits:

- Reduced outage duration costs: $1 million per year (for communications upgrade only - additional future savings would be possible by meshing the transmission system).

Option D: Replace the existing Kelowna wireless system with leased communications services from a telecommunication service provider

Pros:

- Provides communications functionality for SCADA remote control;
- Provides basic tele-protection communications between substations; and
- All communications equipment would be located in existing substation sites.

Cons:

- Complete dependence on third parties for operational and corporate communications;
- Reliability is an issue and difficult to predict as telecom circuits are more likely to fail than equipment and both circuits are prone to the same system failures;
- Does not meet established practices and guidelines for critical tele-protection applications;
- Third-party leased services still required for corporate WAN communications; and
- No system capacity for future Smart Grid initiatives (AMI, etc.).

Costs:

- Capital Costs - $0..63 million
- Ongoing leased communications for corporate WAN: $0.06 million per year
- Ongoing lease costs for operational communications: $0.09 million per year

Benefits:

- Reduced outage duration costs to customers: $0.2 million per year

Option E: Replace existing wireless communication systems with fibre-optic cable and multiplexing equipment without path redundancy

Pros:

- Provides full communications functionality for SCADA remote control;
- Provides full tele-protection communications between substations to support future meshing of transmission system;
- Abundant system capacity for future upgrades to support Smart Grid initiatives (AMI, etc.);
- No dependence on third-parties for operational or corporate WAN communications;
- Good reliability due to use of redundant equipment; and
- Spare fibres severely minimize costs due to technology change in the future as the physical infrastructure will be installed and has long lifespan.

Cons:

- No path redundancy so single event can interrupt communications at multiple sites.

Costs:

- Capital Costs - $3.22 million

Benefits:

- Reduced operating costs for corporate WAN: $0.06 million per year
- Reduced outage duration costs: $1 million per year (for communications upgrade only - additional future savings would be possible by meshing the transmission system).

Option F: Replace existing wireless communication systems with path redundant fibre-optic cable and multiplexing equipment

Pros:

- Provides full communications functionality for SCADA remote control;
- Provides full tele-protection communications between substations to support future meshing of transmission system;
- Abundant system capacity for future upgrades to support Smart Grid initiatives (AMI, etc.);
- No dependence on third-parties for operational or corporate WAN communications;
- Highest reliability due to use of redundant equipment and fibre optic paths (approximately 99.999% system availability); and
- Spare fibres severely minimize costs due to technology change in the future as the physical infrastructure will be installed and has long lifespan.

Cons:

- Not all infrastructure built on transmission structures (4 km on distribution).

Costs:

- Capital Costs - $3.76 million.

Benefits:

- Reduced operating costs for corporate WAN: $0.06 million per year; and
- Reduced outage duration costs: $1 million per year (for communications upgrade only - additional future savings would be possible by meshing the transmission system).

The costs combined with the capabilities of each technology choice are summarized in the table below.

Table 5.1.1 - Kelowna 138 kV Loop Fibre Installation - Option Cost Summary

Option	Capital Cost	NPV Lease Cost[1]	Total Cost	SCADA	Tele-protection	Other Operational Traffic[2]	Highly Reliable[3]	Future Capacity[4]	No Reliance on Third Party	Simplified Maintenance[5]	Fully Redundant
A	$1,816,000	$675,467	$2,491,467	X		X					
B	$5,449,000	$675,467	$6,124,467	X	X		X			X	
C	$6,203,000	$675,467	$6,878,467	X	X	X	X				
D	$631,000	$1,688,668	$2,319,668	X							
E	$3,215,000	$0	$3,215,000	X	X	X	X	X	X	X	
F	$3,761,000	$0	$3,761,000	X	X	X	X	X	X	X	X

[1] NPV Lease Cost uses simplified method to calculate the present value of recurring monthly costs over 30 years (no inflation of lease costs)

[2] Other operational traffic includes operational WAN, phones or corporate WAN services available to substations

[3] A system is considered highly reliable if its availability is sufficient to assume outage length will not be increased by communication failures (>99.95%)

[4] Future capacity considers the ability to accommodate unknown future applications on the infrastructure (assuming high bandwidth)

[5] A system is considered to have simplified maintenance if all maintainable facilities are located within FortisBC assets (substations)

The analysis shows that with the exception of the power line carrier and wireless point-to-point options, all other alternatives were of similar cost (within 15 percent) when considered over a longer time frame.

The redundant fibre option (Option F) is the proposed solution as it provides by far the most functionality, flexibility and performance. Furthermore, it is also the most future-proof system since once the fibre cable infrastructure is constructed; it has a long life (+25 years) when compared to other technologies. Consequently, since communications technologies change rapidly, once the physical infrastructure is in place costs associated with these future upgrades and migrations are greatly reduced. This major benefit of fibre infrastructure has not been captured in this financial analysis, but should not be overlooked as a benefit when comparing the options from a qualitative perspective.

Description of Recommended Option (F)

The following are the fibre route details for the proposed fibre-optic ring:

- 66 km total fibre ring;
- 47.25 km existing on fibre owned or leased via IRU by FortisBC;
- 4.1 km new fibre built on FortisBC distribution structures;
- 1 km new fibre in FortisBC underground duct; and
- 8.6 km new fibre on FortisBC transmission structures.

Figure 5.1.1 - Existing and Proposed Kelowna Area Fibre Network

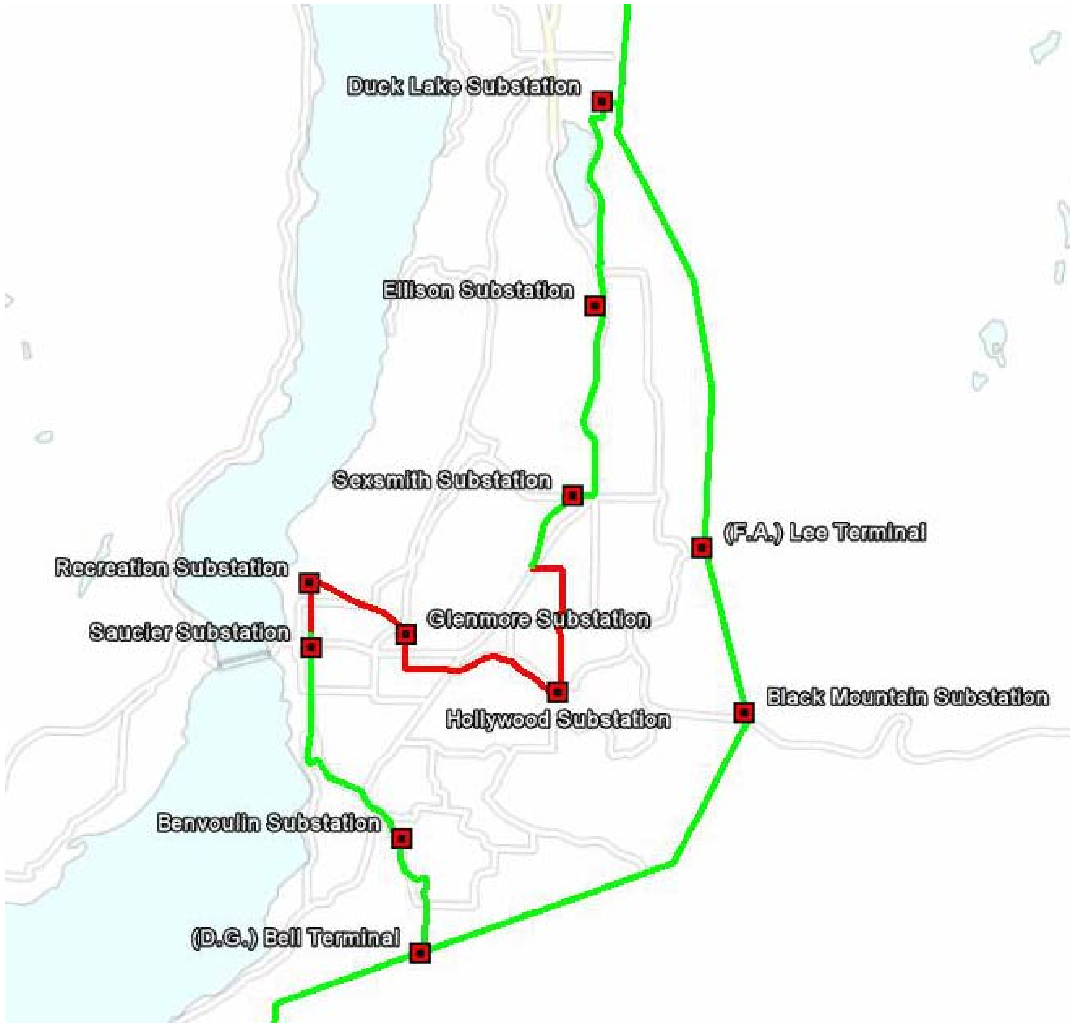


Figure 5.1.1 above depicts the routing of the existing and proposed fibre optic network in the Kelowna area. Existing fibre that FortisBC either owns or has access to via an IRU is shown in green. The red lines indicate the proposed construction required to complete the fibre loop and provide connectivity to the Recreation, Glenmore and Hollywood substations. At peak times, these three major substations combined supply approximately 125 MW of load in the most densely populated portion of Kelowna.

The complete project will improve the safety and reliability for this growing urban area and provide high-bandwidth communications for current-day operations as well as support future initiatives relating to transmission system protection, Smart Grid, Advanced Metering Infrastructure (AMI) or distribution network automation. Furthermore, it will reduce operating costs by eliminating the dependence on third-party leased services both for corporate and operational communications. This fibre will replace existing wireless communication equipment which has reached the end of service life and is becoming increasingly unreliable. Finally, as any new cable will be under-strung on existing FortisBC transmission and distribution structures, no new rights of way or line construction is required. If approved, FortisBC would expect to complete the fibre portion of the project in 2012 and install the communications multiplexers in 2013.

Future Enhancements

The reliability of the Kelowna-area transmission system could be further enhanced in the future by operating the transmission network fully meshed as proposed for the 2014-16 timeframe. This is a separate project that will directly address transmission system protection and operational limitations and improve customer reliability through a reduction primarily in the frequency of wide-scale transmission outages. This would result in additional customer outage savings beyond the $1 million discussed above. This is because a single-contingency transmission outage would not result in even the momentary loss of any load and consequently customer outages would be less frequent. These additional savings are recognized, but are not quantified at this time. Further details and justification for this project will be provided in a future application.

5.2 Telecommunications, SCADA, Protection and Control Sustainment Projects

5.2.1 COMMUNICATION UPGRADES

This project will upgrade and update telecommunications routes and will improve emergency response capability. Some FortisBC telecommunications equipment is near or beyond its designed operational life. Individual components are unreliable, and the manufacturers no longer supply spare parts. In some extreme cases, equipment can no longer be tested or adjusted because it fails when test systems are operated. This results in delays returning equipment to service. This equipment can also cause failure of the transmission and distribution systems it supports or prevent restoration efforts, exposing the system to possible equipment damage, extended outage times and possibly causing public safety issues. FortisBC plans to pursue a two-fold strategy to address this issue; upgrade parts of the telecom system regularly over several years, and prepare an emergency response plan and supply spare new systems that may be used in emergency restoration.

Specifically, the following projects have been identified:

- **Jungle Mux Laser upgrade** - Current Synchronous Optical Network (SONET) backbone speed in the Kootenay area is an Optical Carrier-1 (OC-1, 50 Mbps), and this is scheduled for upgrading to an OC-3 (155 Mbps) in 2012; and
- **Upgrade Backhaul to North Warfield Substation** - Point-Point 900 Megahertz (MHz) MDS LEDR radio has had reliability problems. A replacement 900 MHz or 2 Gigahertz (GHz) link will be examined and installed tentatively in 2013.

Communication upgrades are estimated to cost $0.41 million 2012 and $0.40 million in 2013.

5.2.2 SCADA SYSTEMS SUSTAINMENT

This project will fund the annual sustainment requirements for all Supervisory Control and Data Acquisition (SCADA) and Mandatory Reliability Standards (MRS) related infrastructure and software. This includes sustainment for assets such as Survalent Worldview control software, intrusion detection software, document control software, training management software, electronic security devices, physical security devices and monitors, SCADA servers, SCADA Local Area Network (LAN) and Wide Area Network (WAN) devices, workstations and backup infrastructure.

SCADA system sustainment is estimated to cost $0.71 million in 2012 and $0.73 million in 2013.

6. GENERAL PLANT

General plant consists of vehicles, metering, information systems, telecommunications, buildings, furniture and fixtures, and tools and equipment. Expenditures in 2012-13 also include regulatory and legislative compliance initiatives.

The proposed General Plant projects support British Columbia's energy objectives as defined in the Clean Energy Act, in particular the objectives:

(b) to take demand-side measures and to conserve energy…;

(g) to reduce BC greenhouse gas emissions…; and

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emission in British Columbia.

The proposed projects also support Policy Actions contained in the Energy Plan, in particular Policy Action:

(14) Ensure that the province remains consistent with North American transmission reliability standards.

The following table shows the 2012-13 expenditures for General Plant. FortisBC is requesting approval of the expenditures detailed below with the exception of expenditures related to the following projects:

- Kootenay Long Term Facilities Strategy; and
- Advanced Metering Infrastructure.

As further discussed below, these projects will be the subject of a CPCN application.

Table 6.0 - General Plant Projects

1		2012	2013	Total
2	**General Plant Projects**	**($000s)**		
3	Kootenay Long Term Facilities Strategy	6,020	10,477	16,497
4	Trail Office Lease Purchase	-	10,000	10,000
5	Okanagan Long Term Solution	69	75	144
6	Central Warehousing	1,755	-	1,755
7	Advanced Metering Infrastructure	4,501	27,931	32,432
8	**Information Systems**			
9	Infrastructure Sustainment	1,111	1,118	2,229
10	Desktop Infrastructure Sustainment	1,115	1,122	2,237
11	Application Sustainment	1,179	1,210	2,389
12	Application Enhancements	1,235	1,242	2,477
13	PowerSense DSM Reporting Software	1,032	-	1,032
14	Vehicles	2,541	2,574	5,115
15	Metering Changes	403	406	809
16	Telecommunications	121	183	304
17	Buildings	1,362	883	2,245
18	Furniture and Fixtures	121	122	243
19	Tools and Equipment: Transmission-Distribution-Generation	528	457	985
20	**Subtotal**	**23,093**	**57,800**	**80,893**
21	Demand Side Management (Net of Tax)	5,798	5,909	11,707
22	**Total General Plant**	**28,891**	**63,709**	**92,600**

The following sections provide a brief description of the General Plant requirement for 2012-2013.

6.1 Kootenay Long Term Facilities Strategy

This project is prompted by the aging and inadequate sizing of current facilities at FortisBC's South Slocan, Castlegar, and System Control Centre. A long term space strategy for these sites will be developed and filed as a CPCN to deal with the following key drivers:

- Condition assessment of the South Slocan facilities has identified numerous safety, environmental, structural issues that need to be addressed;
- The System Control Centre site is currently undersized and using a portable trailer. NERC and BC Mandatory Reliability Standards are under review and it is believed a number of site upgrades will be necessary;

- The Castlegar operations site is inadequately sized and the current property entrance/exit to the road is difficult and unsafe;
- Opportunity for synergies in staffing, crew dispatching and shop requirements;
- Opportunity to reduce energy usage - South Slocan administrative were not designed for their current use and due to age of structures have no energy efficiencies built into their design; and

A CPCN is required for this project which will include acquiring land and building a new Operations Centre and modifications/demolitions to existing facilities. The application will identify the alternatives reviewed and associated avoided costs. The CPCN will identify the value to the Company and customer's for developing the long term space strategy that provides:

- Efficiently planned buildings that maximizes square footage, integrates employees and meets FortisBC's current and future needs;
- Prudently eliminates risk around critical response and aged facilities with safety and environmental issues;
- Commits to a community presence in the area the company is serving for the life of the business; and
- Provides energy efficient buildings that meets FortisBC and BC Government's mandates for energy and the environment.

This project is estimated to cost $6.02 million in 2012 and $10.48 million in 2013.

6.2 Trail Office Lease Purchase

The Trail Office lease is a 30 year lease that commenced September 28, 1993 and was approved by Commission Orders G-41-93 and G-41-94. Under the terms of the lease, the Company has the opportunity to purchase the building on September 30, 2013. The total price of the purchase is approximately $10 million. The avoided lease costs would be $1.974 million annually until September 30, 2023. The lease contract does not allow termination, other than by way of the purchase for which the Company is requesting approval. All costs associated with operating and maintaining the Trail office are paid for by the Company. Therefore, the decision of continuing to lease vs. exercising the purchase option is isolated to a lease vs. purchase financial decision. Purchasing the building, including the cost in rate base and avoiding the future lease obligations will result is a Net Present Value benefit to customers of approximately $1.4 million using an 8 per cent discount rate.

6.3 Okanagan Long Term Solution

Currently FortisBC occupies three sites in the Kelowna area Benvoulin, Enterprise and Springfield.

- Benvoulin Operations Centre - is an owned facility/yard combination of office, district warehouse and yard facilities housing line services crews, design, engineering, administrative staff;
- Enterprise Site - is a leased combination of office and yard housing Kelowna area/large capital warehouse, construction and maintenance crews, engineering, planning and administrative staff. The lease for this property expires in December 2012.
- Springfield Office - is a leased facility supporting office and administration staff

The Benvoulin and Springfield locations are challenged with space constraints. The Enterprise site lease expires in December 2012. As identified in Section 6.4 below, the Company will revert back to a Centralized Warehouse facility in Warfield and re-establish a district stores at Benvoulin. A long term space strategy will be developed to deal with the various challenges of each facility. The strategy will look to resolve the lack of space, opportunities of consolidation of groups where synergies can be achieved and improve safety concerns particular to Benvoulin access/egress.

FortisBC received approval (Order G-195-10) in its 2011 Capital Expenditure Plan to develop the long term space strategy. FortisBC plans to spend $0.07 million in 2012 and $0.08 million in 2013.

6.4 Central Warehousing

This project will fund the centralizing of warehousing for FortisBC to the Warfield site. Three main warehouses will consolidate into the one, including the Enterprise site in Kelowna as its lease expires in December 2012. District stores would only have an inventory of emergency materials to deal with outages, as well as staging for kitted materials. The kitted materials would be for jobs that have been designed and planned in advance.

To accommodate the facility requirements of central warehousing the Warfield warehousing space will be increased to an estimated 12,000 square feet. The project costs include the addition of the new warehouse space and the appropriate racking, as well as relocation of the business groups from the Enterprise facility.

By centralizing warehousing to Warfield the additional space leased at the Enterprise site will not need to be replaced when the lease expires. This will reduce costs to the organization by $600,000 annually. The project is estimated to cost $1.76 million in 2012.

6.5 Advanced Metering Infrastructure

6.5.1 APPLICATION HISTORY

On December 19, 2007, FortisBC submitted an application to the BCUC for implementation of AMI throughout its service territory. In order to provide regulatory certainty, FortisBC's approach to the application was to obtain funding approval prior to proceeding with technology selection. The application was amended in March 2008 to include hourly readings and home area network capabilities. Subsequently, three rounds of information requests exchanged between FortisBC, the BCUC and registered interveners with the regulatory process concluding in June 2008.

On December 3, 2008 by Order G-168-08, the BCUC denied FortisBC's AMI application, stating:

> *"The Commission Panel acknowledges the initiative of FortisBC in developing plans and applying for a CPCN for the AMI project. The Commission Panel is also cognizant of the government's goal of having advanced meters and associated infrastructure in place for all utilities in British Columbia in the future. However, in summary, the Commission Panel is of the view that the Application and the Amended Application are incomplete and premature."*

The BCUC also encouraged FortisBC to submit a new application, stating:

> *"The Commission panel encourages FortisBC to continue its efforts to develop, and in due course, reapply for approval of a comprehensive and complete program for the implementation of AMI."*

6.5.2 RE-APPLICATION APPROACH

FortisBC intends to submit a new CPCN application that addresses the issues discussed in the Reasons for Decision accompanying Order G-168-08.

To accomplish this, FortisBC will create a more comprehensive CPCN that includes vendor selection through a formal request for proposal (RFP) process, details regarding the technology chosen and an AMI Future Program study that will quantify the benefits of future applications of AMI technology. The new CPCN application will also summarize the results of collaboration discussions with other BC utilities.

Specifically, the FortisBC AMI project team will:

- Work with operational supervisors to define detailed AMI requirements, by documenting AMI "Use Cases" to be included within the procurement and project management processes;
- Complete the necessary RFP processes to select the most appropriate vendor(s) based on the documented requirements and evaluation criteria defined by the project stakeholders;
- Perform acceptance testing of the AMI system through a technology proof of concept or vendor site visits;
- Compile detailed estimates on the cost of the AMI system for use in the AMI business case and CPCN Application;
- Commission a conservation potential study on the possible benefits of DSM programs that are supported by AMI technologies;
- Document a long term AMI Program Plan describing the functions and features that will be available on implementation as well as those that will be available and used in the future;
- Create a revised business case for AMI based on the long term program plan and AMI Use Cases; and
- Establish preliminary scope, schedule and budget for the AMI Implementation project.

6.5.3 AMI PROGRAM OBJECTIVES

The following are FortisBC's key objectives with respect to the implementation of AMI:

- Improve operational efficiencies by reducing operating costs;
- Improve customer service by increasing the accuracy and timeless of their bills and providing better data to resolve customer concerns;
- Support conservation and efficiency objectives by enabling conservation rates and providing customers with more information on their consumption;
- Protect revenue by identifying and resolving non-technical system losses; and
- Support customer in-home automation by providing usage information and price signals into the customer's home.

6.5.4 AMI PROGRAM SCOPE

The scope of the AMI program at FortisBC is expected to include:

6.5.4.1 Meters and Modules

As part of its AMI program, FortisBC intends to install AMI-enabled meters for all of its direct customers over a two year period beginning in 2013. These meters will be capable of two-way communications and providing hourly interval data.

6.5.4.2 Communications Infrastructure

The AMI communications infrastructure is expected to collect and transfer readings, alarms and other meter data from the metering end points into the system's Head End System (HES). It will also be responsible for providing communications to other downstream devices such as in-home displays or other smart grid devices.

6.5.4.3 IT Infrastructure

The AMI System implementation will include a Meter Data Management System (MDMS) that will be the central repository for all meter related data. The MDMS will integrate with the AMI Head End System which is the application that manages the AMI network. The Head End System will manage the communications, operations, and diagnostic monitoring of the electric meters and field devices.

The integration of FortisBC's core systems such as Customer Information System (CIS) and Geographic Information System (GIS) will also be an integral part of the AMI implementation.

6.5.5 PLANNED USES OF THE AMI SYSTEM

FortisBC undertook an exercise in which the AMI project team worked with operational supervisors to define detailed AMI requirements, by documenting AMI "Use Cases". This methodology has become an industry standard after it was first introduced by Southern California Edison. Table 6.5.5 below describes the planned uses of the AMI system that were defined as part of this processes.

Table 6.5.5 - Planned Uses of the AMI System

Billing	Customer Service	Field Operations Services	AMI Installation and Maintenance	Future Uses
B1 CIS billing system uses AMI data to bill customers	**C1** Customer has access to readings, recent energy usage and cost information	**O1** Distribution operator locates outage using AMI data and restores service	**I1** Utility installs, provisions and configures AMI system	**F1** External clients use the AMI system to interact with customer DSM devices
B4 CIS billing system to bill actual readings on move-in and move-outs	**C3** Customer provides distributed generation via net metering	**O2** AMI system recovers after power outage, communications or equipment failure	**I4** Utility manages overall health of the AMI system	**F2** Contract meter reading for other utilities (including gas and water)
B7 CIS uses Mv-90 system for industrial billing	**C4** Trail Contact Centre uses AMI data to provide support to customers for common questions and concerns	**O3** Utility uses AMI to replace physical disconnection with virtual disconnection		**F6** Utility upgrades AMI system to address future requirements
	C5 Customer has access to consolidated billing options and flexible billing dates	**O5** Distribution operators optimize network based on data collected by the AMI system		**F7** Customer pre-pay
	C7 CSR uses AMI system to gain an on-demand reading	**O6** Operations completes meter related service post AMI		
	C8 Utility detects possible tampering or theft at customer site	**O7** Security Requirements		**Finance and Reporting** R1 Utility uses AMI data for Reporting
		O8 Utility remotely limits or connects / disconnects customer		

6.5.6 PLANNED SCHEDULE

FortisBC expects to issue a CPCN for advanced metering in the summer of 2011. The high level implementation schedule is expected to be as follows:

Table 6.5.6 - Planned Schedule

Task Name	Start Date	End Date
Complete Use Cases and Requirements	06/01/2009	01/01/2010
MDMS RFP Process	09/01/2010	05/05/2011
AMI RFP Process	10/01/2010	06/15/2011
Deployment RFP Process	04/01/2011	06/30/2011
Implementation Planning	03/15/2011	06/15/2011
CPCN Creation & Regulatory Process	02/01/2011	02/17/2012
IT Systems Implementation	03/01/2012	12/31/2012
Communications Deployment	10/31/2012	05/30/2014
Meter Deployment	01/01/2013	12/31/2014

6.5.7 PLANNED BUDGET

A detailed budget will not be available until the RFP processes have been concluded, however, at this time FortisBC is forecasting the project will cost approximately $47.18 million with expenditures of $4.50 million in 2012, $27.93 million in 2013 and $6.10 million in 2014. A detailed budget will be submitted as part of the CPCN application.

6.6 Information Systems

FortisBC's Information Systems expenditures focus on enhancing and upgrading its information system infrastructure and core applications. FortisBC relies on a base of core applications, including SAP (Financial, Human Resources, Project Management and Materials Management), CIS (Customer Information System), SharePoint based Intranet/Internet, AM/FM (Asset and Facilities Management) and Cascade (Plant Maintenance). These applications are used to support the Company's business and technology requirements. FortisBC carefully selected these core systems for their scalability and technology, which allow them to be upgraded, enhanced and integrated without having to acquire and implement new solutions. The Company's strategy is to use the capabilities of these applications to improve safety, reliability, efficiency and customer service.

Upgrades are applied to existing infrastructure, databases and applications to maintain support and avoid potential productivity or reliability issues. Upgrades also ensure new functionality and features that vendors develop through continued investment in their products are available to end users and support staff. The 2012 and 2013 Information Systems sustainment projects have been developed to fund the minimum upgrade requirements for each Information Systems category.

Enhancements to existing systems are initiated when a business requirement or opportunity arises that requires a long term solution. These enhancements do not generally include additional licenses or hardware, but do include configuration, integration and process modification to take advantage of a particular application's inherent functionality.

The 2012 and 2013 capital expenditures for information and business systems are primarily based on enhancing and upgrading existing technologies, system and business applications to leverage the capabilities of the existing applications and to sustain the existing infrastructure primarily in support of AMI. Any enhancements that have been identified outside those required by AMI have been identified as being necessary by the application users in conjunction with the information systems group to maintain or improve business operations in support of the ISP. This is common practice in other organizations that recognize the benefit of enhancing existing systems as compared to acquiring and implementing new systems, and is consistent with FortisBC's previous capital expenditure plans.

The DSM Tracking and Reporting Software project is the only substantial software implementation project, outside of AMI, that is planned in 2012-2013.

The following projects, planned for 2012 and 2013, have been recognized as being critical to improving safety, productivity, customer service and efficiency by enhancing functionality and operability. Table 6.6 below provides details with respect to the projects planned for 2012 and 2013.

Table 6.6 - Information Systems Projects

		2012	**2013**	**Total**
	Information Systems Projects	**($000s)**		
1	Infrastructure Sustainment	1,111	1,118	2,229
2	Desktop Infrastructure Sustainment	1,115	1,122	2,237
3	Application Sustainment	1,179	1,210	2,389
4	Application Enhancements	1,235	1,242	2,477
5	DSM Tracking and Reporting Software	1,032	-	1,032
6	**Total Information Systems Projects**	**5,672**	**4,692**	**10,364**

6.6.1 INFRASTRUCTURE SUSTAINMENT

The infrastructure sustainment project includes replacing out-dated hardware and software (operating systems and related server software) in the primary and backup data centres and supporting infrastructure (switches and routers that tie the Wide Area Network together). There is approximately $3.2 million worth of hardware and software associated with the Company's Information System infrastructure. The life expectancy of the hardware infrastructure components is a maximum of five years, based on industry standards and manufacturers' support, while operating systems are typically upgraded every two years to maintain vendor support. The budget is developed based on the replacement of the oldest equipment (five year maximum life expectancy), failed equipment and minimum software upgrades to maintain manufacturer support. This strategy of asset management avoids the complete replacement of all equipment once every five years and the resource issues and work disruption that would result.

Equipment and software designated for upgrade typically include servers at end of life, disk drives that have passed maximum life expectancy (over twenty terabytes of disk space in each data centre), networking infrastructure replacements (failed switches, routers and hubs) and operating system and database upgrades.

The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and requested expenditures for 2012 and 2013.

Table 6.6.1 - Infrastructure Sustainment Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
358	273	733	796	1,075	1,111	1,118

6.6.2 DESKTOP INFRASTRUCTURE SUSTAINMENT

Desktop Infrastructure Sustainment includes Microsoft Windows operating system, Microsoft Office Suite and other job specific hardware and software upgrades for FortisBC's personal computers (PC) environment. It is a phased approach to keeping approximately 670 PCs current and supportable, rather than replacing all PC equipment and software every five years. The life expectancy of the desktop hardware is a maximum of five years based on industry standards and manufacturers' support. The phased replacement strategy avoids the resourcing and disruption issues that occur with complete replacement of all PC equipment every 5 years. The total value of FortisBC's desktop hardware and related peripherals is approximately $3 million. The Desktop Infrastructure Sustainment budget is developed based on the replacement of the oldest (maximum five year life expectancy) and failed equipment.

This project also includes the costs necessary to replace fax machines, telephones and photocopiers/printers to maintain reliability and compatibility with industry standards. This is also a staged approach based on standard lifecycles.

An asset management tool is used to track the age of all technology assets at FortisBC to ensure they are replaced in a timely manner and to realize maximum life expectancy without jeopardizing productivity.

The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and requested expenditures for 2012 and 2013.

Table 6.6.2 - Desktop Infrastructure Sustainment Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
657	240	783	831	941	1,115	1,122

6.6.3 APPLICATION SUSTAINMENT

This project will fund the annual sustainment requirements for all FortisBC applications including, CIS, SAP, AM/FM and all other applications used at FortisBC. Annual upgrades maintain support and avoid potential productivity or reliability issues, as well as making new functionality and features available that the vendors have developed through continued investment in their products.

The estimated costs for Application Sustainment are $1.18 million in 2012 and $1.21 million in 2013.

6.6.4 APPLICATION ENHANCEMENTS

This project will fund any application enhancements that are required during the year. Enhancements to existing systems are initiated when a business requirement or opportunity arises that requires a long term solution. These enhancements do not generally include additional licenses or hardware, but do include configuration, integration and process modification to take advantage of a particular application's inherent functionality.

Examples of some of the expected enhancements and their drivers:

- The reporting, analysis, and interpretation of business data is of central importance to a company in optimizing decision making. Business Intelligence (BI), SAP NetWeaver provides data warehousing functionality, a business intelligence platform, and a suite of business intelligence tools that delivers this capability. Relevant business information from productive SAP applications and all external data sources are integrated, transformed, and consolidated in BI with the toolset provided. BI provides flexible reporting, analysis, and planning tools to support the Company in evaluating and interpreting data, as well as facilitating its distribution. Businesses are able to make well-founded decisions, predict future possibilities and determine target-orientated activities on the basis of this analysis. Investments will be made in 2012 and 2013 to develop BI in support of the data requirements of the organization for reporting in customer service, operations, finance, HR and GIS data.
- Additions and enhancements will be made to customer systems, such as the internet web site, to enhance customer self-service and information availability. Electronic billing options and capabilities will also be enhanced to broaden customer options.
- Enhancements will be made to improve and automate interfaces between the AM/FM mapping system, CIS and the Survalent Worldview control system. These interfaces allow for a real time view of the electrical network on a scaled map of the electrical system, visibility of vehicle locations in relation to customers and improved restoration information by relating customers to the electrical network.

Other enhancements will be undertaken on a priority, benefit and resource availability basis. These enhancements can be driven by legislative, regulatory or business process changes.

Application enhancements are estimated at $1.24 million in 2012 and $1.24 million in 2013.

6.6.5 POWERSENSE DSM REPORTING SOFTWARE

This project is to implement software to be used by the PowerSense group to track, calculate savings, and report on DSM projects from inception to completion. Due to the expanding and increasing numbers of programs and DSM projects, this software is required to capture the appropriate customer transaction information, improve internal workflow processes to provide better customer service, advance monitoring and evaluation, and ensure optimal expenditures. This software will track interactions with each customer from project initiation to completion and provide robust reporting capabilities. FortisBC does not currently have software that is capable of meeting the requirements of the expanded DSM program. The solution will be selected based on its ability to meet requirements at the most reasonable cost, while aligning with FortisBC application standards.

This project is estimated to cost $1.03 million in 2012.

6.7 Vehicles

This project involves the replacement and/or addition of heavy fleet vehicles, service vehicles, passenger vehicles, light duty vehicles, speciality equipment and off road vehicles necessary for FortisBC to conduct its operations. Fleet also bases planning on the Company's objectives to enhance safety, reliability, customer service, and reduce costs and the Company's environmental footprint.

FortisBC currently has 350 units in its fleet; 287 units are owned and 63 units are leased. In 2012 and 2013, FortisBC plans on replacing 23 and 35 units respectively. FortisBC's equipment replacement guidelines are listed in Table 6.7 (a) below.

Table 6.7 (a) - Replacement Criteria Trigger

Description	Trigger
Passenger Vehicles	160,000 km (Gasoline) 200,000 km (Diesel)
3\4 Tons and Smaller	160,000 km (Gasoline) 200,000 km (Diesel)
Service Vehicles (3\4 and One Tons) 2 and 4 Wheel Drive	160,000 km (Gasoline) 200,000 km (Diesel)
Line Trucks (Digger or Aerial) 2 and 4 Wheel Drive	10 years / 200,000 km
Trailers	20 years
Specialty and Small Horsepower (Forklifts, Snowmobiles, ATVs)	Individual Review

In making the actual replacement decision many key issues are considered including suitability to meet current and future business requirements, ability to maintain adequate safety, age, condition, and compliance with regulations. A replacement decision is done on a unit by unit basis. All units to be replaced have either exceeded their planned life cycle, or, are becoming a safety, reliability or compliance risk. Electric utilities rely on the availability of specialized, reliable, safe, and efficient vehicles. Deferring these planned expenditures has the possibility of negatively affecting employee (and public safety), as well as potentially resulting in increased operating expenses as a result of repair costs and equipment shortages.

Vehicle expenditures include the replacement and\or addition of heavy fleet vehicles, service vehicles, passenger/light duty vehicles, and specialty equipment and off-road vehicles necessary for FortisBC to conduct its operation in a safe and cost effective manner.

Fleet represents approximately 78 percent of FortisBC's greenhouse gas emissions. The Company currently has seven hybrid low emission passenger vehicles and a hybrid low emission service truck. Also, in concert with FortisBC Energy Inc., the Company has begun exploring opportunities for using natural gas vehicles. The Company will continue to monitor and evaluate the progress of all new green vehicle technologies as part of its future purchases.

Table 6.7 (b) - Number of Vehicles per Year

	2007	2008	2009	2010	2011	2012	2013
Total Number of Units in Fleet	329	351	342	348	350	350	352

The number of vehicles in the fleet has been stable over the last five years, averaging 344 units. This trend is expected to continue as vehicle replacements, and not additions, will remain the focus.

Table 6.7 (c) below lists the type of units that are planned to be replaced in 2012 and 2013. Included in the expenditure forecasts is an allowance of approximately $100,000 per year to address any unanticipated purchases, or unplanned replacements.

Table 6.7 (c) - Planned vehicle replacements 2012-2013

Category	2012 Units	2013 Units
Heavy Vehicles	3	5
Service Vehicles	10	11
Passenger/Light Vehicles	9	12
Specialized/Off-Road Vehicles	1	7
Total	23	35

The estimated cost for replacement and/or addition of vehicles and related equipment is $2.54 million in 2012 and $2.57 million in 2013.

6.8 Meter Changes

This project involves the purchase of new revenue metering infrastructure driven by customer growth as well as replacement for metering equipment that fails during the metering compliance or meter re-test program. Metering infrastructure includes meters, current transformers, potential transformers and ancillary equipment.

This project is estimated to cost $0.40 million in 2012 and $0.41 million in 2013.

6.9 Telecommunications

The telecommunications capital budget is used to purchase new or replacement communications equipment. This equipment includes landline equipment, VHF (Very High Frequency) field communications equipment, microwave substation controls and the installation of isolation equipment when installing Telus lines into substations. These installations will provide voice as well as data and control communications as required.

The communications budget also covers upgrades and/or replacement of equipment that is used for remote control and operation of field devices from the System Control Centre.

This project is estimated to cost $0.12 million in 2012 and $0.18 million in 2013.

6.10 Buildings

FortisBC has 15 office/yard sites (ranging in age from 8 to 88 years) throughout its service territory, totalling approximately 228,800 square feet of office, shop and warehouse space and approximately 51 acres of yard space. Of this, 125,000 square feet is owned, and 104,500 square feet is leased. The Buildings project is composed of three projects greater than $100,000 in value and a group of projects individually valued under $100,000. The group of projects under $100,000 will be managed as if it were one large project. The estimated expenditure for the project is $1.36 million in 2012 and $0.88 million in 2013.

The Facility Upgrade Project as described below is primarily required to carry out property upgrades and building repairs necessary to meet operational requirements in a safe, efficient and environmentally conscious manner. Site audits have been carried out at all facilities and the information has been used to identify deficiencies and upgrades to each facility.

Site visits were also conducted with Operations personnel to identify any upgrades required for safety, health and work efficiencies.

6.10.1 WARFIELD OPERATIONS DRAINAGE PROJECT

The drainage project is a continuation of recent upgrades to the storm sewer systems in the Warfield yard, and is intended to minimize the environmental impact of spills and runoff. The areas under the pole storage bunks will be paved, an oil separator installed, and a connection to the new drainage system will be completed in this phase of the project. This project will reduce the risk of possible negative impact on the environment.

6.10.2 OLIVER HEATING, VENTILATION AND AIR CONDITIONING (HVAC) UPGRADES

The Oliver site HVAC systems require replacement. They currently are inefficient and provide a low level of comfort for office work. These will be replaced with modern, high efficiency units with new ductwork. The energy requirements will be reduced for the facility, lowering operating costs and increasing worker comfort.

6.10.3 EMERGENCY BUILDING UPGRADES

This project is required to address unforeseen issues that arise that cannot be deferred to the next planning cycle, such as breakdown of heating, ventilation and air conditioning systems, and other building systems.

The projects will be executed as scheduled in the budget year unless a new, previously unidentified project deemed of higher priority is approved by Management to replace it. This list of projects may then change throughout the year.

6.11 Furniture and Fixtures

This project is required for the replacement of furniture that has reached the end of its life cycle, as well as the addition/modification of furniture and fixtures to accommodate changing needs within the organization.

The Company maintains an inventory of furniture at all sites. The condition of the furniture was assessed placing it in one of three categories (disposal, poor and good). Using this process together with our Environment Health and Safety Standard 108, (Section 2.2) *Monitoring the Work Environment*, the capital requirements are upgraded each year. Typically chairs are replaced every five years and workstations are reviewed for functionality every eight to ten years.

The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and requested expenditures for 2012 and 2013.

Table 6.11 - Furniture and Fixtures Expenditures

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
248	237	294	268	182	121	122

6.12 Tools and Equipment

This project involves the purchase of tools and equipment necessary to construct, operate, and maintain the generation, transmission, and distribution system. This budget covers all capital expenditures for tools and equipment in excess of $1,000, in accordance with the Company's capitalization policy, and includes replacement tools that have reached the end of their service life and additional tools that are more appropriate for the various trades from an ergonomic and/or safety perspective.

The following table shows the actual expenditures for the years 2007 to 2010 as well as the forecast for 2011 and plan for 2012 and 2013.

Table 6.12 - Tools and Equipment

2007	2008	2009	2010	2011	2012	2013
Actual				Forecast	Requested	
($000s)						
936	587	525	507	622	528	457

7. DEMAND SIDE MANAGEMENT

Demand Side Management (DSM) or energy efficiency programs have been offered to FortisBC customers since 1989 and are available to all customers served by FortisBC and its wholesale customers of Grand Forks, Kelowna, Nelson Hydro, Penticton, and Summerland.

FortisBC's 2012 Long Term DSM Plan can be found in Volume 2 of the 2012 Integrated System Plan. The 2012-13 DSM Plan is an extension of the 2011 DSM Plan which received approval via Commission Order G-195-10 on December 17, 2010. The 2012-13 DSM Plan programs, budget and energy savings targets are based on the 2011 base year, and are escalated as appropriate using the ramp rates provided in the 2010 Conservation and Demand Potential Review (CDPR).

Planned gross expenditures are $7.73 million in 2012 and $7.88 million in 2013, or $5.80 and $5.91 million respectively, net of tax effect. The 2011 approved DSM expenditure is $7.84 million gross and $5.67 million net. This level of expenditure supports provincial policy that places demand side management as a priority resource to meet growing electricity demand in British Columbia as per the specific requirements in the Utilities Commission Act and the DSM Regulation.

The 2012-13 DSM plan portfolio includes programs for the residential, commercial, industrial and irrigation customer classes and is intended to capture economic potential savings identified in the CDPR. There are also portfolio-level expenditures for supporting initiatives, and planning and evaluation.

The 2012-13 DSM plan addresses the Policy Actions contained in the 2007 Energy Plan, in particular the following three:

(1) to acquire 50 percent of… incremental resources needs through conservation by 2020;

(2) ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia; and

(3) encourage utilities to pursue cost effective and competitive demand side management opportunities.

The 2012-13 DSM Plan was also developed in the context of the DSM Regulation, as discussed in the 2012 Long Term DSM. It includes programs that are mandated to meet the adequacy provisions of the 2008 DSM Regulation, namely measures for rental and low income customers, education (elementary and secondary) and post-secondary schools .

Table 7.0 below is a summary table of the proposed 2012-13 DSM energy savings, expenditures by sector, portfolio level and totals (gross and net of tax), and the Benefit/Cost Ratios for 2012-13 by program sector and overall. There is a significant drop in the energy savings forecast in the 2012-13 plan years, primarily due to an extraordinary industrial project expected to occur in 2011. When the extraordinary project is subtracted from the 2011 savings target of 39,722, the underlying "base" savings target is 32,282 MWh. More details are evident in Table 7.4 (Industrial Programs).

Table 7.0 - 2012-13 Demand Side Management Plan

1	Programs	2011 Approved		2012 Plan		2013 Plan		TRC
		Savings (MWh)	Cost ($000s)	Savings (MWh)	Cost ($000s)	Savings (MWh)	Cost ($000s)	Benefit/ Cost Ratio
2	Residential	16,422	3,636	16,101	3,717	16,946	3,944	1.6
3	Commercial	13,940	2,118	13,380	2,199	11,980	2,085	1.7
4	Industrial	9,360	613	2,480	350	2,580	364	3.9
5	**Sub-total Programs only**	**39,722**	**6,367**	**31,961**	**6,266**	**31,506**	**6,393**	**1.6**
6	Supporting Initiatives		725		725		725	
7	Planning & Evaluation		750		740		760	
8	**Total (incl. Portfolio spend)**		7,842		7,731		7,878	**1.5**
9	Income Tax Impact		(2,078)		(1,933)		(1,969)	
10	**Total deferred (net of tax)**		5,764		5,798		5,909	

The Lighting and Irrigation programs are included in the Commercial sector due to their relatively small magnitude. The targets for Lighting and Irrigation are provided in the Commercial section.

7.1 Residential Sector Programs

Although the number of new homes being built has decreased significantly within the service area since 2008, the renovation and energy retrofit market remains strong. It is expected that the residential sector will continue to provide the greatest amount of savings over the 2012 DSM Plan timeline. The following table outlines the list of residential programs, plan costs and savings, and the Benefit/Cost ratio on a Total Resource Cost basis. A description of each incentive program and the primary delivery mechanisms follows.

Table 7.1 - Residential Programs (2012-13)

1	Programs	2011 Approved		2012 Plan		2013 Plan		TRC Benefit/ Cost Ratio
		Savings (MWh)	Cost ($000s)	Savings (MWh)	Cost ($000s)	Savings (MWh)	Cost ($000s)	
2	Building Envelope	5,460	1,379	4,530	1,195	4,890	1,290	1.4
3	Heat Pumps	3,397	694	3,397	703	3,397	698	1.1
4	Lighting	3,420	438	2,530	328	2,467	313	1.9
5	New Home	105	54	90	43	93	45	1.2
6	Appliances	680	245	690	247	739	267	1.0
7	Electronics	180	49	370	58	727	113	3.2
8	Water heating	960	162	1,040	186	1,383	277	3.5
9	Low Income & Rental	540	305	1,774	677	1,570	660	1.6
10	Behavioural	1,680	310	1,680	280	1,680	281	5.1
11	**Total**	**16,422**	**3,636**	**16,101**	**3,717**	**16,946**	**3,944**	**1.6**

7.1.1 BUILDING ENVELOPE

The major component of the Home Improvement Program (HIP) is building envelope improvements (insulation, air sealing and Energy Star windows and doors). The HIP program will maintain incentive levels from 2011. Program delivery will be primarily through partnerships with LiveSmart BC and will focus on a "whole house" approach. Individual components of the program like heat pumps and Energy Star appliances and lighting will also be marketed separately, as described below.

7.1.2 HEAT PUMP PROGRAM

With its temperate winters and hot summers, the FortisBC service area is an ideal climate for energy efficient heat pumps. The program will continue with the current rate of incentives for owners to upgrade electric heating systems to either air source heat pumps, ductless (mini) heat pumps or geo-exchange systems. As an alternative to a direct financial incentives, FortisBC will also provide low-interest loans for qualifying customers at a below market interest rate (4.9 percent).

To ensure more customers attain the maximum efficiencies available with heat pump technology, a heat pump maintenance program will be introduced, and on a pilot basis, a duct sealing program for homes with electric heat will be introduced.

A programmable thermostat rebate program will continue.

7.1.3 RESIDENTIAL LIGHTING PROGRAM

It is estimated that 21 percent of all electrical use within the FortisBC service area is attributed to lighting. To help build market transformation and improve customer participation in lighting incentive programs, FortisBC will continue to partner with large and small retailers to provide “instant rebates” at the point of purchase. Rebates will be provided for speciality Energy Star rated CFL and LED lamps and hard-wired luminaires.

7.1.4 NEW HOME PROGRAM

To encourage whole home energy efficiency, via performance path, two levels of incentives to achieve an EnerGuide rating of 84 or 90 will be offered. To further promote home ratings, FortisBC will offer incentives for energy evaluations. However, if homeowners or builders do not chose to rate their homes, incentives for the most efficient insulation and heating and cooling technologies will continue to be offered as a prescriptive option. New home builders and customers will also be eligible for the Energy Star appliance and lighting rebates.

Funding for engineering studies and other assessments will also be provided to encourage energy efficient technologies for larger single-family developments and multi-family buildings.

7.1.5 ENERGY STAR APPLIANCES AND ELECTRONICS

The existing rebate program for the highest tier Energy Star clothes washers, refrigerators and freezers, dishwashers, bathroom fans and televisions will continue. Appliance retailers will provide the rebates at the point of purchase or assist customers to fill out the application forms to provide a high level of customer service. A refrigerator and freezer pick-up program, operated in conjunction with appliance dealers, will facilitate the permanent removal of the old, inefficient appliances.

7.1.6 WATER HEATING

Approximately 50 percent of FortisBC customers’ water is heated with electricity. To encourage efficient water heating, FortisBC will continue to offer rebates for the installation of solar hot water systems and heat pump water heaters for customers with electrically heated water. Low flow showerheads will be distributed via Energy Saving Kits and trade show product samples.

7.1.7 LOW-INCOME HOUSEHOLDS PROGRAM

FortisBC will continue to provide low income households with Energy Saving Kits and distribute them directly to qualified customers, primarily through low-income service providers like food banks and low-income housing groups.

In collaboration with the provincial government and other public utilities, FortisBC will provide a direct installation program which includes the basic and some more extended energy conservation measures. The program will employ screening tools to determine which measures are appropriate and cost effective for each application. It is expected the measures will primarily be insulation of ceilings and attics and draft-proofing, as well as Compact Fluorescent lighting products. Energy Star bathroom fan(s) will likely be installed to address ventilation concerns. Other types of measures, such as window replacement, would only be considered in situations where the home had very poor windows or for individual replacement of broken or damaged units.

A direct-install Lighting program, similar in execution to the LiveSmart Small Business lighting program, will be instituted for common area lighting, examples of which include corridors, stairwells, and lobbies.

7.1.8 RENTAL ACCOMMODATION PROGRAMS - SINGLE AND MULTI-FAMILY

Beginning in 2012-13, in collaboration with other public utilities, FortisBC will direct-market financial incentive offers to landlords, property managers and rental agencies to upgrade rental properties. Similar to the LiveSmart collaborative program, a suite of “whole home” rebates and incentives for energy building evaluations will be offered. Additional information collateral that target renters directly will also be provided to help inform landlords and renters.

The Multi-Family program will have the same components as the Single-Family program but will also include: a social marketing tactic using tenant-based energy saving teams to encourage behavioural changes; and energy audits and financial incentives to encourage landlords to invest in “whole building” retrofits (insulation, draft-proofing and windows and doors) and energy efficient lighting

7.1.9 RESIDENTIAL BEHAVIOURAL PROGRAM

Behavioural programs seek to achieve long-term change in existing patterns of customer energy usage through the use of specific measures (products) along with messaging to establish Conservation Culture norms. For example PowerSense has given away thousands of clotheslines since 2009, in order to enable customers to avoid using their electric clothes dryer when the weather is suitable. Along with the clotheslines itself, a couple of dozen clothespins are provided to each participant, so the alternative of hanging laundry can be put to immediate use. The recipient signs a pledge sheet to use the clotheslines, and concurrent marketing messages promote clothesline usage as a desirable social norm.

Following the implementation of the Advanced Metering Infrastructure (AMI) project, an incentive will be offered to customers to purchase an in-home display (IHD), which extracts information from the AMI meter to better inform users of their energy usage and costs. The IHDs will provide near real-time information regarding customers' energy usage, encouraging them to conserve and/or shift loads.

Again this measure will be accompanied with education materials to suggest alternatives and substitutions to the electrical loads encountered. Examples include: hanging laundry, delaying the need to switch on central air conditioning by maximizing the use of natural ventilation and shading first, and unplugging the numerous phantom power consuming devices when not in use.

7.2 Commercial Sector Programs

Program offers for the Commercial sector will remain consistent in 2012 other than the Building Optimization Program, which will move from the pilot project phase to full implementation. The following table outlines the list of commercial programs, plan costs and savings, and the Benefit/Cost ratio on a Total Resource Cost basis. A description of each incentive program and the primary delivery mechanisms follows.

Table 7.2 - Commercial Programs

1	Programs	2011		2012		2013		TRC
		Approved		Plan		Plan		Benefit/ Cost Ratio
		Savings (MWh)	Cost ($000s)	Savings (MWh)	Cost ($000s)	Savings (MWh)	Cost ($000s)	
2	Lighting	7,130	1,080	7,140	1,120	7,140	1,170	1.6
3	BIP	3,010	572	3,410	659	3,460	696	1.8
4	Computers	240	34	250	37	270	42	2.3
5	Municipal	2,980	386	2,000	298	530	88	1.1
6	Irrigation	580	46	580	85	580	89	5.7
7	**Total**	**13,940**	**2,118**	**13,380**	**2,199**	**11,980**	**2,085**	**1.7**

7.2.1 LIGHTING

Incentives for lighting measures are varied, with the rebate limited to achieving a two-year payback on incremental cost. Most incentives will be applied at point-of-purchase through product rebates provided through the authorized lighting wholesalers in the FortisBC service area. For specialty lighting and complex retrofits, customers will be encouraged to contact PowerSense directly for a customized rebate.

FortisBC will also promote and incent adaptive street light technologies (street lights capable of dimming), and LED lighting products, for municipalities and customers with large parking lots.

7.2.2 LIGHTING DIRECT INSTALLATION PROGRAM

In partnership with LiveSmart BC (Ministry of Energy and Mines), in 2012-13 FortisBC will continue to deliver a lighting direct installation program for small businesses that use less than $20,000 of electricity per year. FortisBC's portion of the incentive for the program is based on an estimate of the kWh saved.

7.2.3 BUILDING IMPROVEMENTS PROGRAM (BIP)

Program assistance and financial incentives include a free assessment of the building and where a more detailed assessment is required, 50 percent of the cost of an approved study. FortisBC also will provide rebates towards the incremental cost of efficiency measures compared to standard "baseline" construction The rebate entitlement is based on estimated annual kWh savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost.

In addition, FortisBC will offer a suite of standardized fixed rebates (product option) for the most common heating, ventilation and air conditioning (HVAC) measures, pumps and motors, compressed air and refrigeration technologies.

7.2.4 COMPUTERS - DATA CENTRE AND SERVER PROGRAM

To encourage the use of the most efficient technologies and measures, FortisBC will provide financial incentives and tools to help commercial customers identify and implement server consolidation solutions in their data centres. The program would include data centre assessment studies to identify consolidation (virtualization software and hardware consolidation) opportunities and best approaches to improving energy efficiency in data centres.

7.2.5 MUNICIPAL PROGRAMS

FortisBC will continue to offer a “Partners in Efficiency” Program for local governments. In addition to the incentives offered in the form of rebates and financial incentives, PowerSense representatives will work closely with the municipalities’ staff to help determine the economics for energy efficiency upgrades to new and existing facilities, and street lighting.

In addition, municipalities are continuing to work to reduce carbon emissions and are investigating innovative energy efficient technologies, which FortisBC will support if electrical savings are anticipated.

7.2.6 BUILDING OPTIMIZATION PROGRAM (BOP)

The Building Optimization Program targets large commercial customers with multiple facilities, providing them with a dashboard tool with which to continuously monitor and track their energy usage. FortisBC provides the metering data tie-in and funds the BoP software cost and in exchange the customer agrees to implement all measures identified in a comprehensive audit.

7.2.7 IRRIGATION PROGRAMS

The irrigation program budget for 2012-13 is almost double that of 2011 due to an increase in the underlying incentive rate. Access to the program will be made simpler through energy efficiency product rebates will be made available for irrigation components, pump rebuilds or replacements and low-medium pressure pivots. Rebates are offered for replacing a standard efficiency pump motor to a premium efficiency pump motor and variable speed digital controls. In response to requests from irrigation customers, FortisBC has increased the minimum motor size at which “soft-start” pump motor controls are required and simplified the process for approving larger pump motors without “soft-start” controls. Soft-start controls help ensure that electric motors do not affect power quality, but add to the cost of switching to high-efficiency motors.

Product incentives will be offered with Point-of-Sale “instant” rebates through participating irrigation retailers/wholesalers to ensure energy-efficient options are chosen. Irrigation case studies will be profiled in the Powerlines newsletter to raise awareness and attract more participants from this rate class.

7.3 Industrial Sector Programs

The following table outlines the two proposed industrial programs, plan costs and savings, and the Benefit/Cost ratio on a Total Resource Cost basis. A description of each incentive program and the primary delivery mechanisms follows. The 2012-13 plan costs and savings are considerably less than 2011 due to an extraordinary project in the current fiscal year.

Table 7.3 - Industrial Efficiency Programs

1	Programs	2011 Approved		2012 Plan		2013 Plan		TRC
		Savings (MWh)	Cost ($000s)	Savings (MWh)	Cost ($000s)	Savings (MWh)	Cost ($000s)	Benefit/ Cost Ratio
2	EMIS	80	10	190	27	290	41	0.8
3	Industrial Efficiency	1,840	231	2,290	323	2,290	323	5.7
4	Celgar	7,440	372	-	-	-	-	-
5	**Total**	**9,360**	**613**	**2,480**	**350**	**2,580**	**364**	**3.9**

7.3.1 ENERGY MANAGEMENT INFORMATION SYSTEMS (EMIS)

This is a process optimization program for which FortisBC will provide financial incentives based on calculated energy savings and operational assistance for the purchase of process optimization technology. EMIS will help customers optimize energy efficiency by monitoring and tracking their energy usage on a production basis (kWh/unit). Recommended strategies are identified through an investigation process with additional focus on documentation and training to realize persistence of savings. The customer also agrees to implement all measures identified.

7.3.2 INDUSTRIAL EFFICIENCY

FortisBC will offer customized assistance and financial incentives for industrial customers to achieve increased efficiency. This will include free initial assessment of energy use, and where a more detailed assessment is required, 50 percent of an approved study's costs. FortisBC also will provide rebates towards the incremental cost of efficiency measures compared to standard "baseline" construction (the rebate entitlement is based on estimated annual kWh savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost).

7.3.3 SUPPORTING INITIATIVES

The following supporting initiatives are vital to the success of the 2012 DSM Plan because they provide the program support, education (of customers and students), build trade ally capacity and promote market transformation which are necessary to enable the potential savings that have been identified. The supporting initiatives, which complement the incentive-based programs listed beforehand, are characterized as portfolio level spending since they do not result in direct DSM savings. The following table lists the components and plan expenditures for the 2012-13 budget years, which are unchanged from the approved 2011 expenditures for supporting initiatives.

Table 7.3.3 - Supporting Initiatives

1	Programs	2011	2012	2013
		Approved	Plan	
		Cost ($000s)		
2	Public Awareness	200	200	200
3	Community Energy Planning	250	250	250
4	Trades Training	100	100	100
5	Education (schools)	150	150	150
6	Codes and Standards	25	25	25
7	**Total**	**725**	**725**	**725**

7.3.3.1 Public Awareness

This component seeks to increase public awareness of energy efficiency and conservation matters, and educates customers in regards to the availability of DSM programs. To promote the Company's incentive programs, collateral such as brochures, posters, point-of-sale materials, business case reports and promotional items is required. Collateral and promotional items will be distributed to residential customers at trade shows and community events. It will also be provided to trade allies (electrical contractors, appliance retailers, heat pump contractors) for distribution to customers. The point-of-sale materials highlighting energy efficiency and conservation will be provided to wholesale and retail partners who sell energy efficiency equipment.

Targeted information campaigns with specific messaging about programs and energy efficiency will be purchased for trade magazines, newsletters and other industry focused information pieces.

FortisBC will use Community-Based Social Marketing (CBSM) approach to help achieve the behaviour changes needed to achieve a "conservation culture". Research shows that behaviour change programs can achieve measurable savings by influencing customer behaviour to conserve energy or invest in more energy efficient technologies. The CBSM tactics to be used for message delivery include: public relations, community outreach, strategic partnerships, behaviour pledges/commitments, product sampling, promotional contests and media educational campaigns. Some social networking tools will also be used. The following describes the specific educational programs to be implemented.

- PowerSense Month: an educational campaign during October which includes an interactive contest for customers and a multi-media information campaign focusing on energy efficient heating and winterizing homes. FortisBC will also host the annual PowerSense Awards to honour the businesses and individuals that make the greatest energy conservation efforts in their communities.

- Lighting awareness campaigns: to encourage customers to make use of day-lighting, turn off all unnecessary lights and switch to energy efficient lighting. Earth Hour and the energy efficient lighting program will be the "event drivers" for this messaging.

- Cooling and heating awareness: educational campaigns to be run in early summer and fall to encourage customers to set back/up thermostats, heat only occupied areas of a home, maintain weatherproofing, close windows and blinds, etc. In conjunction with an advertising campaign, consumer intercept activities are planned at building supply stores and trade shows to encourage people to draft proof and insulate their homes appropriately.

- Electronics and phantom power awareness: in combination with the electronics rebate program, phantom power messaging will be promoted during the fall and winter seasons.
- Laundry program: to promote the purchase of Energy Star Tier 3 clothes washers, the use of cold water wash and drying clothes on clotheslines. Promotion will include clothesline product sample give-aways, behaviour pledges and community outreach in partnership with municipal governments and FortisBC Energy Inc..
- Appliance program: in conjunction with the appliance rebate programs, an intensive information campaign will be conducted to build awareness and encourage behaviour change regarding appliance use: such as, maintaining proper refrigeration temperatures and minimizing use of hot water. Hot water and refrigerator/freezer temperature gauge give-aways will help enforce the messaging.

7.3.3.2 Community Energy Planning

Provincial legislation requires all local governments to identify Greenhouse Gas (GHG) reduction targets, policies, and actions in their Official Community Plans (OCP) and Regional Growth Strategies. As a result, BC local governments are completing energy and greenhouse gas emissions plans for their communities and are seeking support from public utilities. As the community energy plans directly impact future electrical use and may include significant energy savings attributed to good planning, it is appropriate to support communities in their efforts. To assist communities and help strategize to achieve greater energy efficiencies, FortisBC will support community energy studies and planning sessions.

7.3.3.3 Trades Training

FortisBC provides sponsorships for training and support for a number of initiatives from the building trades and electrical non-profit trade organizations[1], as well as support for energy management planning training like Natural Resources Canada's "Spot the Savings" workshops. Committed to growing the energy efficiency knowledge amongst the trades, FortisBC will continue to provide this support.

FortisBC will work closely with FortisBC Energy Inc. and BC Hydro to provide leadership to help develop new training opportunities that support energy efficiency, as well as provide greater financial support for programming.

7.3.3.4 Education Programs

Public Schools

FortisBC has long supported elementary, middle and high school energy conservation education initiatives through financial sponsorship of educational events (such as science fairs and tours) and programs (Environmental Mind Grind, Climate Change Showdown) and delivery of curriculum approved longer-term educational programs through non-profit organizations like the Pacific Resource Conservation Society's Destination Conservation program. In 2009, FortisBC, in collaboration with (then) Terasen Gas, BC Hydro and the BC Ministry of Energy, Mines and Petroleum Resources, contracted the services of a consulting company to design a curriculum-based Grade 11 course on energy and energy conservation.

FortisBC will continue to build on existing partnerships and seek additional opportunities in 2012-13.

Post-Secondary

FortisBC continues to support energy efficiency training opportunities such as the Okanagan College "Home for Learning", and providing guest lecturers upon request e.g. Selkirk College Environmental program.

[1] TECA (Thermal Environmental Comfort Association), SICA (Southern Interior Construction Association), CHBC (Canadian Home builders Association), BCSEA (BC Sustainable Energy Association), GeoExchangeBC, etc.

PowerSense is in discussions with FortisBC Energy Inc. to develop more fulsome offerings for this education segment, including the possibility of student intern positions, and instructing building energy software modelling at UBCO's Engineering faculty.

7.3.3.5 Codes and Standards

A number of international and national organizations like the Consortium for Energy Efficiency, the Canadian Standards Association, and Natural Resources Canada are working to set new efficiency standards for many consumer electronics, appliances, and lighting products amongst other equipment and technologies. Similarly local, provincial and federal governments are setting policy and regulations to increase as-built energy efficiency performance or raise awareness (e.g. EnerGuide building ratings). FortisBC will support codes and standards policy development and research, through in-kind and financial co-funding arrangements.

PowerSense also co-funds a contract compliance officer, in collaboration with other public utilities, to ensure that market transformation on energy efficiency measures - once regulated - is completed.

7.4 Planning and Evaluation

Planning and evaluation of the DSM initiatives are required to properly plan and control the proposed DSM expenditures and ensure the resource acquisition goals are prudently met. This expenditure includes provisions for planning and evaluation staff, as well as external expertise and facilitating the DSM Advisory Committee. The following table shows the major planning and evaluation components and the plan cost for 2012-13.

Table 7.4 - Planning and Evaluation

1	**Programs**	**2011**	**2012**	**2013**
		Approved	**Plan**	
		Cost ($000s)		
2	Salaries (loaded)	420	400	420
3	Office Expenses	60	50	50
4	Consulting Fees	75	80	80
5	M&E Reports	185	200	200
6	DSMAC	10	10	10
7	**Total**	**750**	**740**	**760**

The major steps of the DSM planning cycle are anticipated to be repeated at approximately five year intervals, unless circumstances change. The major steps, which are detailed in the 2012 DSM Plan, include end-use studies, and a Conservation Demand Potential Review resulting in an updated DSM Plan which is subject to due process (public consultation and filing).

Updating the FortisBC DSM Plan at regular intervals ensures that new and emerging commercially available DSM measures are taken into account, avoided cost assumptions are updated and the appropriate program course corrections are made.

7.5 Monitoring and Evaluation

Appendix D to the 2012 Long Term DSM Plan contains the Monitoring and Evaluation Plan, for the 3-year period 2012-2014 inclusive. This plan is necessary to ensure that the DSM program expenditures will yield the savings expected and that the programs are operating effectively. The Monitoring and Evaluation Plan recommends that two major program reviews and three mini-reviews be undertaken each calendar year, and that recent behavioural initiatives promoting the use of measures such as clotheslines are also reviewed for effectiveness.

Monitoring and Evaluation of energy efficiency programs provides internal and external accountability by reducing uncertainty in the estimates of energy and demand savings, and by determining the cost effectiveness of these programs compared to other energy resource options. A Monitoring and Evaluation study of a demand-side management or energy efficiency program involves:

- Objective and systematic measurement of program operations and performance;
- Use of social-science (behaviour) and engineering data and methods;
- Verifying actual (achieved) energy and demand savings attributable to the program;
- Estimating permanent changes in the market penetration (market transformation) of energy efficient technologies attributable to the program; and
- Providing a basis for future decisions related to a program or portfolio of programs (modifies, expands, or discontinues).

Appendix A

TRANSMISSION LINE CONDITION ASSESSMENTS

Transmission Condition Assessment Data

20 Line Work Summary

Structure #	Type of Rehab	Comments
28	Structure Replace	Replace light angle structure with Distribution underbuild - Pole & Transmission/Distribution arms in poor condition
33	Repair	Reframe Distribution to alley arm; Reframe Neutral higher on pole for low clearance issues
34	Repair	Reframe Neutral to arm
35	Repair	Reframe Neutral to arm
39	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is blue tagged (stubbed)
61	Repair	Replace Transmission tangent insulation
70	Repair	Reframe structure to floating Double Dead End H-Frame with cross bracing
72	Repair	Replace Transmission tangent insulation
73	Repair	Reconductor river crossing with 477 ACSR Hawk; Add marker balls
	Repair	Install single Stockbridge dampers on Transmission forespan
	Repair	Salvage existing marker ball span and structures
74	Structure Replace	Replace Double Dead End (3-Pole) structure- Poles in poor condition
BEP	Repair	Replace Transmission insulation with synthetic
	Repair	Reconductor aft span to structure 20L73 with 477 ACSR Hawk; Replace Transmission drops
79	Repair	Replace missing keeper pin on CP east Transmission phase
		Engineer Review - Check jumper insulation and arm - Possible replace
87	Repair	Remove old pole
88	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
89	Repair	Add structure tag #
90	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
91	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
92	Repair	Add new side anchor for angle
		Note: Easement required for new anchor or possible push brace
94	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
		Note: Easement required for structure
96	-	Note: Easement required for existing anchor
97	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed (Transmission arm is failing)
98	Structure Replace	Replace tangent structure with Distribution Double Dead End underbuild & transformer - Pole is stubbed (Transmission arm is failing)
99	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
100	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed

Transmission Condition Assessment Data

20 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
101	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
102	Repair	Remove old pole
103	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
106	Repair	Remove old pole
109	Structure Replace	Replace angle structure with Distribution underbuild; Reframe to Double Dead End - Pole is stubbed
		Note: Easement required for structure
110	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
111	Repair	Remove old pole
113	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
114	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
117	Structure Replace	Replace angle structure with Distribution underbuild - Pole is stubbed
118	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
119	Structure Replace	Replace tangent structure with Distribution Double Dead End underbuild - Pole is stubbed
120	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
123	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
130	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
131	Structure Replace	Replace tangent structure with Distribution Double Dead End underbuild - Pole is stubbed
132	Structure Replace	Replace tangent structure with Distribution underbuild & taps - Pole is stubbed
133	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
134	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
135	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
136	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
137	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
139	Structure Replace	Replace tangent structure with Distribution underbuild & transformer/tap, OHG pole - Pole is stubbed
140	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
141	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
142	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed

Transmission Condition Assessment Data

20 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
143	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
144	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
145	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
146	Structure Replace	Replace tangent structure with Distribution Double Dead End underbuild & tap - Pole is stubbed
147	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
149	Structure Replace	Replace tangent structure with Distribution underbuild & taps - Pole is stubbed
150	Structure Replace	Replace tangent structure with Distribution Double Dead End underbuild - Pole is stubbed
151	Structure Replace	Replace angle structure with Distribution underbuild & taps - Pole is stubbed
		Note: Easement required for new anchor
152	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
		Note: Easement required for structure
159	Structure Replace	Replace tangent structure with Distribution underbuild & tap, breast anchor - Pole is stubbed
160	Structure Replace	Replace tangent structure with Distribution underbuild & transformer/tap - Pole is stubbed
161	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
162	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
163	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
164	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
165	Structure Replace	Replace tangent structure with Distribution underbuild & transformer/tap - Pole is stubbed
166	Structure Replace	Replace tangent structure with Distribution underbuild & tap, breast anchor - Pole is stubbed
167	Structure Replace	Replace tangent structure with Distribution underbuild & tap, breast anchor - Pole is stubbed
168	Structure Replace	Replace tangent structure with Distribution underbuild & tap, breast anchor - Pole is stubbed
169	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
170	Structure Replace	Replace tangent structure with Distribution underbuild & taps - Pole is stubbed
171	Structure Replace	Replace angle structure with Distribution underbuild & transformer - Pole is stubbed

Transmission Condition Assessment Data

20 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
171	Structure Replace	Replace angle structure with Distribution underbuild & transformer - Pole is stubbed
192	Repair	Replace Distribution tangent arm
		Refarme Distribution tap off pole - May need to add conductor
		Engineer Review - Anchoring support for Distribution tap needs review
214	Structure Replace	Replace light angle structure with Distribution underbuild & tap - Pole is stubbed
215	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
		Note: Easement required for new anchor
216	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
219	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
220	Structure Replace	Replace light angle structure with Distribution underbuild - Pole in poor condition
221	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
223	Structure Replace	Replace tangent structure with Distribution underbuild with transformer/tap - Pole is stubbed
224	Structure Replace	Replace light angle structure with Distribution underbuild & dip - Pole is stubbed
225	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
228	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
233	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
	Repair	Replace secondary tap structure
234	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
236	Structure Replace	Replace angle structure with Distribution underbuild - Pole is stubbed
238	Structure Replace	Replace light angle structure with Distribution underbuild - Pole in poor condition
239	Structure Replace	Replace tangent structure with Distribution underbuild - Pole in poor condition
240	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
241	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
242	Structure Replace	Replace light angle structure with Distribution underbuild & transformer - Replace with adjacent structures
243	Structure Replace	Replace light angle structure with Distribution underbuild - Replace with adjacent structures
244	Structure Replace	Replace light angle structure with Distribution underbuild & transformer - Pole is stubbed
246	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed

Transmission Condition Assessment Data

20 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
247	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
248	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
249	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
250	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
252	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed (Distribution arm is failing)
253	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
		Note: Review secondary Highway clearances
254	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
255	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed (Transmission arm is failing)
257	Structure Replace	Replace tangent structure with Distribution underbuild & transformer/tap - Pole is stubbed
258	Structure Replace	Replace light angle structure with Distribution underbuild & transformer - Pole is stubbed
259	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
261	Repair	Add new anchor for Distribution tap
		Add stirrups for Distribution tap; Add elephant ears to Distribution cutout
264	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed (Distribution arm is failing)
265	Structure Replace	Replace light angle structure with Distribution underbuild & transformer - Pole is stubbed
266	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
267	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
268	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
269	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
270	Structure Replace	Replace light angle structure with Distribution underbuild & transformer - Pole is stubbed
271	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
272	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
273	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
		Note: Easement may be required for new anchor
274	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
275	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
276	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
277	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
278	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
279	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed

Transmission Condition Assessment Data

20 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
281	Structure Replace	Replace light angle structure with Distribution underbuild & tap - Pole is stubbed
282	Structure Replace	Replace light angle structure with Distribution underbuild & transformer - Pole is stubbed
283	Structure Replace	Replace light angle structure with Distribution underbuild & transformer - Pole is stubbed
284	Structure Replace	Replace light angle structure with Distribution underbuild & transformer - Pole is stubbed
287	Structure Replace	Replace light angle structure with Distribution underbuild & guy - Pole is stubbed
288	Repair	Replace structure tag # to '20L288'
		Note: Distribution double circuit Double Dead End arm guyed to structure #287 - Repair with future work
289	Structure Replace	Replace light angle structure with Distribution double circuit underbuild - Pole & Distribution arm in poor condition
290	Repair	Replace structure tag # to '20L290'
		Note: Anchoring needs to be re-designed with future structure replacement
293	Repair	Refurbishment of Transmission switch
		Note: Distribution double circuit Double Dead End arm guyed to structure #294 - Repair with future work
295	Repair	Refurbishment of Transmission switch
297	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
301	Repair	Remove old pole
305	Repair	Repair Wood Pecker hole at Transmission skypin bolt
312	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
313	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
314	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed (Distribution arm is failing)
315	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
316	Structure Replace	Replace light angle structure with Distribution underbuild - Replace with adjacent strs
317	Structure Replace	Replace light angle structure with Distribution underbuild - Pole in poor condition
321	Repair	Add push brace for angle
330	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
336	Structure Replace	Replace tangent structure with Distribution underbuild - Pole & Transmission arm in poor condition
340	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
341	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed

Transmission Condition Assessment Data

20 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
342	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
343	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
344	Repair	Add new anchor for Distribution tap
	Repair	Reframe Neutral tap 0.6m higher - Rubbing on Telus
361	Repair	Add stirrup and cutout/lightning arrestor for transformer
364	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed (Arm is failing)
365	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
371	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
372	Structure Replace	Replace tangent structure with Distribution underbuild - Replace with adjacent structures
373	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
378	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
379	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
380	Structure Replace	Replace tangent structure with Distribution underbuild & transformer - Pole is stubbed
389	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
404	Repair	Add new anchor for Distribution tap
		Note: Easement required for new anchor
411	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
413	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
415	Structure Replace	Replace tangent structure with Distribution underbuild & openers - Pole is stubbed
416	Structure Replace	Replace tangent structure with Distribution underbuild - Replace with adjacent strs
417	Structure Replace	Replace light angle structure with Distribution underbuild - Pole in poor condition
418	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
419	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
420	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
429	Repair	Repair ground wire
432	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
433	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
434	Structure Replace	Replace tangent structure with Distribution underbuild & openers - Pole is stubbed (Transmission arm is failing)
460	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
461	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
462	Structure Replace	Replace tangent structure with Distribution underbuild - Replace with adjacent structures

Transmission Condition Assessment Data

20 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
468	Structure Replace	Replace tangent structure with Distribution underbuild & openers - Pole is stubbed
473	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
479	Repair	Remove old pole
481	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
496	Structure Replace	Replace tangent structure with Distribution underbuild & tap - Pole is stubbed
498	Repair	Add anchor for 3Ø Distribution tap
499	Structure Replace	Replace Double Dead End structure with Distribution underbuild & tap - Pole is stubbed
503	Structure Replace	Replace Transmission switch structure with Distribution underbuild - Design review of switch is needed

Transmission Condition Assessment Data

27 Line Work Summary

Structure #	Type of Rehab	Comments
6	Repair	Add horizontal jumper posts
11	Repair	Repair Wood Pecker holes
23	Repair	Replace Overhead Guy structure - Pole in poor condition & low road clearance
29	Repair	Repair Wood Pecker holes
56	Repair	Replace CØ pole top insulator - Poor access
58	Repair	Salvage old pole
64	Repair	Reframe Fiber & add protective cable cover - Rubbing on Neutral on aft span
86	Repair	Replace Transmission arm and insulation with double arms and angle pin insulators
98	Repair	Repair Wood Pecker holes
	-	Engineer Review - Check condition of Transmission arm - Possibly tighten hardware
102	Repair	Install new anchors (fore & aft) on RP - Check guy clearance over road - Confirm
		Repair Wood Peckers holes on LP and CP
108	-	Engineer Review –structure appears to have 100lbs of uplift at -30°C - Should be OK
113	-	Engineer Review - Check condition of Transmission arm and insulators - Should be OK
125	Repair	Repair Wood Pecker holes
130	Repair	Rosemont Station - Replace missing keys on Tower-Y adapters
138	Repair	Repair Wood Pecker holes
151	-	Note: Auto DE on 477 Hawk to be replaced
	-	Note: Anchor to be a Double Dead End NW for full Double Dead End
155	Repair	Salvage old pole - Transfer secondary (Nelson Hydro) & Telus
156	Repair	Salvage old pole - Transfer secondary (Nelson Hydro) & Telus
162	Repair	Tighten Transmission pole top hardware; Add lock nuts and lock washers
163	-	Note: structure needs re-design for 477 reconductor provision
168	-	Engr Review –structure appears to have 50lbs of uplift at -30°C - Should be OK
170	Repair	Repair Wood Pecker holes
174	-	Reframe Distribution underbuild crossing to floating Double Dead End (Nelson Hydro)
	-	Replace secondary attachment hardware (Nelson Hydro)
178	Repair	Add horizontal jumper posts
197	-	Salvage old pole underneath line at +48m (Nelson Hydro)

Transmission Condition Assessment Data

27 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
249	Repair	Replace Transmission Double Dead End arms & insulation - Arm badly splitting; Add inline anchors
253	Brushing	Brushing required on aft span
	Repair	Replace Transmission tangent arm and insulation
258	Repair	Replace Neutral spool - Possibly reframe to Distribution arm
	Repair	Repair Wood Pecker holes
266	Repair	Add new anchors (fore & aft) - For full 477 deadend capacity
	Repair	Reframe outside phase jumpers to suspension
270	Repair	Reframe Transmission double arm due to snow load concerns – Needs structure-design
271	Repair	Reframe Transmission double arm due to snow load concerns – Needs structure-design
273	Repair	Reframe Transmission double arm due to snow load concerns – Needs structure-design
276	Repair	Reframe Transmission double arm due to snow load concerns – Needs structure-design
277	Repair	Reframe Transmission double arm due to snow load concerns – Needs structure-design
280	Repair	Reframe Transmission double arm due to snow load concerns – Needs structure-design
281	Repair	Reframe Transmission double arm due to snow load concerns – Needs structure-design
289	Repair	Reframe Transmission to floating Double Dead End (flat) on arm
	-	Engineer Review –structure appears to have 400lbs of uplift at -30°C - Confirm design
302	-	Engineer Review - Check arm and anchor capacity - Should be OK
306	Repair	Add new anchors (fore & aft) - For full 477 deadend capacity
	Repair	Reframe outside phase jumpers to suspension
325	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
327	Structure Replace	Replace tangent structure with Distribution underbuild - Pole is stubbed
336	Repair	Reframe Transmission to floating Double Dead End (flat) on arm
	-	Engineer Review –structure appears to have ~500lbs of uplift at -30°C - Confirm design
337	Structure Replace	Replace light angle structure with Distribution underbuild - Pole is stubbed
347	-	Note: Auto Dead End on 477 Cosmos (Hwy slackspan) - Replace with future work
349	Repair	Replace Transmission tangent arm and insulation

Transmission Condition Assessment Data

27 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
355	Repair	Replace Distribution ties
	-	Note: Transmission-Distribution spacing is insufficient - Cannot lower Distribution arm due to low clearance
356	Repair	Replace Distribution ties
359	Repair	Replace Distribution ties
360	Repair	Replace Distribution ties
361	Repair	Reframe 1Ø Distribution arm 1m lower
364	Repair	Reframe 1Ø Distribution arm 1m lower
365	Repair	Replace Transmission light angle arm and insulation
366	Repair	Replace Transmission light angle arm and insulation
370	Repair	Reframe 1Ø Distribution arm 1m lower
	Repair	Reframe Distribution tap lower; Add stirrup for Distribution tap
	-	Engr Review - Check condition of Transmission arm - Should be OK
371	Repair	Replace Transmission light angle arm and insulation
376	Structure Replace	Replace vertical Double Dead End structure- Pole in poor condition
377	Structure Replace	Replace vertical Double Dead End structure- Pole is stubbed
384	Repair	Replace Transmission tangent arm and insulation
385	Repair	Replace Transmission arm and insulation with double arms and angle pin insulators
386	Repair	Replace Transmission arm and insulation with double arms and angle pin insulators
401	Repair	Add horizontal jumper posts
	Repair	Tighten guy wires
407	Structure Replace	Replace tangent structure- Pole is stubbed
408	Structure Replace	Replace tangent structure- Pole in poor condition
409	Structure Replace	Replace tangent structure- Pole is stubbed
411	Repair	Add split bolt to pole top
424	Repair	Add new anchor for Distribution - Confirm
	-	Note: Transmission CØ not changed out with recent work - Replace with future work
433	Repair	Replace Distribution 3Ø tap arm; Add stirrups for Distribution tap
437	Repair	Reframe Distribution arm 1m lower; Reframe Neutral to Distribution arm
438	Repair	Reframe Neutral to arm - Low clearance
439	Repair	Reframe Neutral to arm - Low clearance
440	Repair	Reframe Neutral to arm - Low clearance
441	Repair	Reframe Neutral to arm - Low clearance
	Repair	Add stirrup for Distribution tap
	Repair	Tighten guy wires

Transmission Condition Assessment Data

27 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
446	-	Note: Reframe Distribution arm 1m lower; Neutral on arm
447	-	Note: Replace tangent structure with Distribution underbuild
448	-	Note: Replace angle structure with Distribution Double Dead End
450	-	Note: structure in slight uplift at -30°C - Should be OK
452	Repair	Salvage old pole
456	Repair	Reframe Neutral to Double Dead End
	-	Engineer Review - Check Transmission arm capacity - Should be OK
458	Repair	Replace Transmission arm and insulation with double arms and angle pin insulators
461	Repair	Replace Transmission arm and insulation with double arms and angle pin insulators
	Repair	Add stirrups for Distribution tap
462	-	Engineer Review - Check condition of Transmission arm and insulation - Should be OK
468	-	Engineer Review - Check Neutral clearance on fore span
471	Repair	Replace Transmission arm and insulation with double arms and angle pin insulators
472	Repair	Replace Transmission arm and insulation with double arms and angle pin insulators
476	-	Note: Neutral rubbing on guy wire - Add insul-link rod with future work
479	-	Note: Cotter key on Distribution tap deadend shoe is not all the way in
480	Repair	Replace Transmission insulation with double angle pin insulators (re-use Transmission arms)
484	Repair	Tighten guy wires
498	Repair	Tighten Neutral hardware; Add lock nut and lock washer
533	Repair	Salvage old pole
555	Repair	Add backfill for Transmission anchor
	Repair	Perform on Overhead Guy pole bottom guy wire not completed
556	Repair	Add backfill for Distribution tap anchor
568	Structure Replace	Replace tangent structure with dbl Distribution underbuild and Transmission/Distribution taps; Replace Overhead Guy pole
568A	Structure Replace	Replace structure and reframe to Transmission dead end with double Distribution tangent underbuild
568B	Structure Replace	Replace structure and reframe to double Distribution Double Dead End; Salvage Transmission
569	Structure Replace	Replace light angle structure with double Distribution underbuild & transformer; Replace Overhead Guy pole
570	Structure Replace	Replace tangent structure with double Distribution underbuild and Transmission/Distribution taps
571	Structure Replace	Replace tangent structure with double Distribution underbuild & transformer and 2x Transmission taps; Replace Overhead Guy pole

Transmission Condition Assessment Data

21 Line Work Summary

Structure #	Type of Rehab	Comments
2	Structure Replace	Replace tangent structure- Reject pole from 2007 Teat and Treat data
4	Structure Replace	Replace tangent structure- Pole is stubbed
7	-	Engineer Review - Check clearances for wire transpose on fore span
9	Structure Replace	Replace light angle structure- Reject pole from 2007 Teat and Treat data
11	Structure Replace	Replace tangent structure- Reject pole from 2007 Teat and Treat data
12	Structure Replace	Replace light angle structure- Pole in poor condition
13	Structure Replace	Replace light angle structure (double arms) - Pole top in poor condition & Wood Pecker holes
16	Repair	Replace Transmission CØ pole top insulator
17	Structure Replace	Replace tangent structure- Pole is stubbed - Reject pole from 2007 Teat and Treat data
23	Structure Replace	Replace tangent structure- Pole to be stubbed from 2007 Test and Treat data
23A	Structure Replace	Replace tangent structure- Pole & arm in poor condition - Tagged 'Do Not Climb'
25	Repair	Replace broken bells on bottom phase
	-	Engineer Review - Possible low clearance issues on fiber underbuild
26	Structure Replace	Replace tangent structure- Reject pole from 2007 Teat and Treat data

Transmission Condition Assessment Data

22 Line Work Summary

Structure #	Type of Rehab	Comments
5	Structure Replace	Replace tangent structure- Pole is stubbed
6	Structure Replace	Replace light angle structure (double arms) - Pole is stubbed
7	Structure Replace	Replace tangent structure- Pole is stubbed
9	Structure Replace	Replace tangent structure- Pole is stubbed
11	Structure Replace	Replace tangent structure- Pole is stubbed - Reject pole from 2007 Teat and Treat data
12	Structure Replace.	Replace tangent structure (double arms) - Pole is stubbed
13	Structure Replace	Replace tangent structure (wire transpose on fore span) - Pole is stubbed
15	Repair	Add guy guards; Tighten loose guy wires
18	Structure Replace	Replace 3-pole Double Dead End structure- Left pole is stubbed
19	Structure Replace	Replace tangent structure- Pole is stubbed
20	Structure Replace	Replace tangent structure- Pole is stubbed
21	Structure Replace	Replace tangent structure- Pole is blue tagged to be stubbed
22	Structure Replace	Replace tangent structure- Pole is stubbed - Reject wood stub from 2007 Teat and Treat data
24	Structure Replace	Replace tangent structure- Pole is stubbed - Reject pole from 2007 Teat and Treat data
25	-	Engineer Review - Check condition of pole – Possible structure replace
28	Repair	Add horizontal jumper posts
29	Structure Replace	Replace tangent structure- Pole is stubbed
30	-	Engineer Review - Check jumper clearance to pole - Possibly install horizontal posts
36	Structure Replace	Replace tangent structure- Older pole with rotten Transmission arm
37	-	Engineer Review - Check condition of pole – Possible structure replace
38	Structure Replace	Replace tangent structure- Pole is blue tagged to be stubbed from 2007 Teat and Treat data
39	Structure Replace	Replace tangent structure- Pole is stubbed
40	Structure Replace	Replace tangent structure- Pole is blue tagged to be stubbed from 2007 Teat and Treat data
43	Structure Replace	Replace tangent structure- Older pole with rotten Transmission arm
44	Structure Replace	Replace Double Dead End (flat) structure- Pole is stubbed (pole top showing signs of tracking)
45	Structure Replace	Replace light angle structure- Pole is stubbed
46	Structure Replace	Replace light angle structure- Pole is stubbed
47	Structure Replace	Replace light angle structure- Insulation in poor condition and needs new anchoring

Transmission Condition Assessment Data

23 Line Work Summary

Structure #	Type of Rehab	Comments
2	Structure Replace	Replace Double Dead End (vertical) structure- Pole is stubbed
3	Structure Replace	Replace tangent structure- Pole is stubbed
4	Structure Replace	Replace tangent structure- Pole is stubbed (Transmission arm is failing)
5	Structure Replace	Replace tangent structure- Pole is stubbed
6	Structure Replace	Replace tangent structure- Pole is stubbed
7	Structure Replace	Replace tangent structure- Pole is stubbed
11	Structure Replace	Replace tangent structure- Pole is stubbed
12	Structure Replace	Replace tangent structure- Pole is stubbed
13	Structure Replace	Replace tangent structure- Pole is stubbed
17	Structure Replace	Replace tangent structure- Pole is stubbed - Reject pole from 2007 Teat and Treat data
20	Structure Replace	Replace tangent structure- Pole is stubbed
23	Structure Replace	Replace heavy angle structure- Pole is stubbed
26	Repair	Remove old pole
31	Structure Replace	Replace tangent structure- Pole is stubbed
35	Structure Replace	Replace tangent structure- Pole is stubbed
36	Structure Replace	Replace heavy angle structure- Pole is stubbed
37	Structure Replace	Replace tangent structure- Pole is stubbed
38	Structure Replace	Replace tangent structure (double arms) - Pole is stubbed
41	Structure Replace	Replace 3-pole Double Dead End structure- Right/center poles are stubbed
45	-	Engineer Review - Check condition of pole - Possible tangent (with tap) structure replace
46 (tap)	Structure Replace	Replace tangent structure- Pole is stubbed
49	Structure Replace	Replace tangent structure- Pole is stubbed
50	Structure Replace	Replace tangent structure- Pole is stubbed
55	Structure Replace	Replace tangent structure- Pole is stubbed
58	Structure Replace	Replace Double Dead End (vertical) structure- Pole in poor condition
60	-	Engineer Review - Check condition of pole - Possible Double Dead End (vertical) structure replace
	-	Engineer Review - Check jumper clearance to pole - Possibly install horizontal posts
61	Structure Replace	Replace light angle structure- Pole in poor condition
68	Structure Replace	Replace tangent structure- Pole is stubbed
69	-	Engineer Review - Check condition of pole - Possible tangent structure replace
71	-	Engineer Review - Check condition of pole - Possible tangent structure replace
72	Structure Replace	Replace tangent structure- Pole and Transmission arm in poor condition

Transmission Condition Assessment Data

23 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
74	Repair	Replace broken bell on right phase
75	Structure Replace	Replace light angle structure(dbl arms) - Pole in poor condition - Possible rock set
76	Structure Replace	Replace light angle structure- Pole and Transmission arm in poor condition
77	Structure Replace	Replace tangent structure- Pole is blue tagged to be stubbed from 2007 Teat and Treat data

Transmission Condition Assessment Data

24 Line Work Summary

Structure #	Type of Rehab	Comments
1	Structure Replace	Replace tangent structure- Pole is stubbed
4	Structure Replace	Replace Double Dead End (vertical) structure- Pole is stubbed
6	Structure Replace	Replace tangent with Distribution underbuild structure- Pole and Transmission arm are in poor condition
10	Structure Replace	Replace tangent structure- Pole is stubbed - Reject pole from 2007 Teat and Treat data
13	Structure Replace	Replace tangent structure- Pole is stubbed
14	Structure Replace	Replace tangent structure- Pole is stubbed
17	Structure Replace	Replace heavy angle structure- Pole is stubbed
18	Structure Replace	Replace heavy angle structure- Pole is stubbed
19	Structure Replace	Replace tangent structure- Pole is stubbed
21	Structure Replace	Replace tangent structure- Pole is stubbed
22	-	Engineer Review - Check uplift on Distribution underbuild - Possibly re-frame to floating Double Dead End
26	Structure Replace	Replace heavy angle structure- Pole is stubbed
27	Structure Replace	Replace light angle structure- Pole is stubbed
28	Structure Replace	Replace tangent with Distribution underbuild structure- Pole is stubbed
30	Structure Replace	Replace tangent structure- Pole is stubbed
33	Structure Replace	Replace light angle structure- Pole is stubbed - Reject pole from 2007 Treat and Treat data
34	Structure Replace	Replace tangent structure- Pole is stubbed
36	Structure Replace	Replace tangent structure- Pole is stubbed
38	Structure Replace	Replace tangent structure- Pole is stubbed
39	Structure Replace	Replace tangent structure (double arms) - Pole is stubbed
41	Repair	Tighten arm hardware
42	Repair	Add guy guard; Tighten loose guy wires
46	Structure Replace	Replace 3-pole Double Dead End - Center pole is stubbed
47	Structure Replace	Replace tangent structure- Pole is stubbed
48	Structure Replace	Replace tangent structure- Pole is stubbed
49	Structure Replace	Replace tangent structure- Pole is stubbed
50	Structure Replace	Replace tangent structure- Pole is stubbed
51	Structure Replace	Replace tangent structure- Pole is stubbed
53	Structure Replace	Replace tangent structure (rockset) - Pole is stubbed
56	Repair	Add guy guard; Tighten loose guy wires
	-	Engineer Review - Check jumper clearance to pole - Possibly install horizontal posts
58	-	Engineer Review - Check jumper clearance to pole - Possibly install horizontal posts

Transmission Condition Assessment Data

24 Line Work Summary cont'd

Structure #	Type of Rehab	Comments
64	Structure Replace	Replace tangent structure (double arms) - Older pole with Transmission arms in poor condition
65	Structure Replace	Replace tangent structure- Pole is stubbed - Reject wood stub from 2007 Teat and Treat data
66	Structure Replace	Replace tangent structure- Pole is stubbed
67	Structure Replace	Replace tangent structure- Pole is stubbed
68	Structure Replace	Replace tangent structure- Pole is stubbed
69	Structure Replace	Replace tangent structure- Pole is stubbed
70	Structure Replace	Replace light angle structure- Pole is stubbed
71	Structure Replace	Replace Double Dead End (flat) structure-structure in poor condition - Replace with adjacent structures
72	Structure Replace	Replace heavy angle structure- Pole is stubbed
73	Structure Replace	Replace light angle structure- Pole is stubbed
74	Structure Replace	Replaces tangent structure- Pole is stubbed

2012 – 2013 Revenue Requirements
(2012-13 RRA)

Tab 7
Financial Schedules

June 30, 2011

FortisBC Inc.

Table of Contents

REVENUE REQUIREMENTS OVERVIEW

		Actual 2010	Forecast 2011	Approved 2011	Increase (Decrease)	Forecast 2012	Increase (Decrease)	Forecast 2013
					($000s)			
1	Sales Volume (GWh)	3,046	3,187	3,162	31	3,193	39	3,233
2	Rate Base	945,637	1,071,197	1,093,241	52,012	1,145,253	66,928	1,212,181
3	Return on Rate Base	7.77%	7.96%	7.67%	-0.10%	7.57%	-0.01%	7.55%
4								
5	**REVENUE DEFICIENCY**							
6								
7	**POWER SUPPLY**							
8	Power Purchases	71,964	75,956	81,212	9,772	90,984	7,837	98,821
9	Water Fees	9,256	8,977	9,381	300	9,681	172	9,853
10		81,220	84,933	90,593	10,072	100,665	8,009	108,674
11	**OPERATING**							
12	O&M Expense	46,148	53,885	53,885	287	54,172	1,622	55,794
13	Capitalized Overhead	(9,529)	(10,777)	(10,777)	(57)	(10,834)	(324)	(11,159)
14	Wheeling	4,050	4,243	3,338	1,387	4,725	508	5,233
15	Other Income	(6,452)	(7,402)	(5,455)	(2,026)	(7,481)	316	(7,165)
16		34,217	39,949	40,991	(409)	40,582	2,122	42,704
17	**TAXES**							
18	Property Taxes	12,238	13,917	13,940	592	14,532	553	15,085
19	Income Taxes	4,544	9,440	6,733	(681)	6,052	1,811	7,862
20		16,782	23,357	20,673	(89)	20,584	2,364	22,947
21	**FINANCING**							
22	Cost of Debt	35,138	39,364	40,505	814	41,319	2,234	43,553
23	Cost of Equity	38,293	45,922	43,292	2,060	45,352	2,650	48,002
24	Depreciation and Amortization	41,771	45,350	45,498	5,900	51,399	1,829	53,228
25		115,201	130,636	129,296	8,774	138,070	6,714	144,784
26								
27	Prior Year Incentive True Up	(2,690)	(2,770)	(1,089)	709	(380)	380	-
28	Flow Through Adjustments	2,385	2,406	(2,129)	(276)	(2,406)	2,406	-
29	ROE Sharing Incentives	(325)	2,630	448	(3,079)	(2,630)	2,630	-
30		(630)	2,266	(2,770)	(2,646)	(5,416)	5,416	-
31								
32	**TOTAL REVENUE REQUIREMENT**	**246,791**	**281,141**	**278,783**	**15,701**	**294,484**	**24,625**	**319,109**
33								
34	ADJUSTED REVENUE REQUIREMENT					294,484		319,109
35	**LESS: REVENUE AT APPROVED RATES**					283,289		298,618
36	**REVENUE DEFICIENCY for Rate Setting**					**11,195**		**20,490**
37								
38	**RATE INCREASE 2012-13**					**4.00%**		**6.90%**
39	**RATE INCREASE 2014-16 (1)**	**Year 2014:**	**5.8%**					
		Year 2015:	**11.4%**					
		Year 2016:	**5.1%**					

Note (1): Rate increases for 2014-2016 are based on Company's best information at the time of filing the 2012-13 Revenue Requirements Application and will be updated in future Applications

Note: Minor differences due to rounding

SCHEDULE 1 – UTILITY RATE BASE

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
			($000s)		
1	Plant in Service, January 1	1,273,476	1,403,617	1,533,337	1,619,327
2	Net Additions	130,141	129,720	85,990	125,932
3	Plant in Service, December 31	1,403,617	1,533,337	1,619,327	1,745,259
4					
5	Add:				
6	CWIP not subject to AFUDC	7,213	6,237	5,875	5,875
7	Plant Acquisition Adjustment	11,912	11,912	11,912	11,912
8	Deferred and Preliminary Charges	16,698	19,408	25,731	29,899
10		1,439,440	1,570,893	1,662,845	1,792,946
11	Less:				
12	Accumulated Depreciation				
13	and Amortization	323,203	352,464	385,146	421,382
14	Contributions in Aid of Construction	93,763	97,049	104,641	111,698
15		416,967	449,513	489,787	533,080
16					
17	Depreciated Rate Base	1,022,473	1,121,380	1,173,058	1,259,865
18					
19	Prior Year Depreciated Utility Rate Base	915,158	1,022,473	1,121,380	1,173,058
20					
21	Mean Depreciated Utility Rate Base	968,815	1,071,926	1,147,219	1,216,462
22	Add:				
23	Allowance for Working Capital	5,756	7,361	1,654	1,007
24	Adjustment for Capital Additions	(28,934)	(8,090)	(3,620)	(5,288)
25					
26	Mid-Year Utility Rate Base	945,637	1,071,197	1,145,253	1,212,181

Note: Minor differences due to rounding

SCHEDULE 1A – NON RATE BASE ASSETS[1]

		BCUC Order No. [2]	Forecast 2011	Forecast 2012	Forecast 2013
1	**Assets**			($000s)	
2	**Regulatory Assets**				
3	(a) Deferred Income Tax	G-37-84, G-193-08	101,089	113,019	126,611
4	(b) Brilliant Terminal Station Lease Costs	G-2-04, G-193-08	5,424	5,715	5,970
5	(c) Brilliant Power Purchase Agreement Lease Costs		-	60,299	67,225
6	(d) Asset Retirement Obligation	G-184-10	1,022	1,706	2,392
7	(e) Trail Office Building Lease Costs	G-41-93, G-193-08	1,104	973	-
8	(f) Other Post-Employment Benefits		-	5,764	5,468
9	(g) Defined Benefit Pension		-	28,800	27,537
10	(h) Uncertain Tax Positions		-	-	-
11			**108,639**	**216,275**	**235,203**
12	**Other Assets**				
13	(b) Brilliant Terminal Station Capital Lease	G-2-04, G-193-08	19,932	19,220	18,508
14	(c) Brilliant Power Purchase Agreement Capital Lease		-	205,813	201,081
15	(d) Asset Retirement Costs	G-184-10	2,281	1,683	1,085
16	(i) Financing Costs Under Effective Interest Method	G-184-10	758	796	804
17	(j) Embedded Derivative Valuation Adjustment		-	-	-
18			22,971	227,512	221,479
19	**Total Non-Rate Base Assets**		**131,610**	**443,787**	**456,681**
20	**Liabilities**				
21	**Regulatory Liabilities**				
22	(i) Financing Costs Under Effective Interest Method	G-184-10	(758)	(796)	(804)
23	(j) Embedded Derivative Valuation Adjustment		-	-	-
24			(758)	(796)	(804)
25	**Other Liabilities**				
26	(a) Deferred Income Tax	G-37-84, G-193-08	(101,089)	(113,019)	(126,611)
27	(b) Brilliant Terminal Station Capital Lease	G-2-04, G-193-08	(25,356)	(24,935)	(24,478)
28	(c) Brilliant Power Purchase Agreement Capital Lease		-	(266,112)	(268,306)
29	(d) Asset Retirement Obligation	G-184-10	(3,303)	(3,389)	(3,478)
30	(e) Trail Office Building Lease	G-41-93, G-193-08	(1,104)	(973)	-
31	(f) Other Post-Employment Benefits		-	(5,764)	(5,468)
32	(g) Defined Benefit Pension		-	(28,800)	(27,537)
33	(h) Uncertain Tax Positions		-	-	-
34			(130,852)	(442,991)	(455,877)
35	**Total Non-Rate Base Liabilities**		**(131,610)**	**(443,787)**	**(456,681)**
36					
37	**Net Non-Rate Base Assets**		**-**	**-**	**-**

Note (1): The inclusion of Non Rate Base Assets in the 2012-13 RRA is discussed further in Appendix A.

Note (2): Deferral recognition has been approved through the Orders listed above.

Note: Minor differences due to rounding

TABLE 1 – A – UTILITY PLANT IN SERVICE (2011)

Line	Account		December 31 2010	Additions	Retirements	December 31 2011
		Hydraulic Production Plants		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	12,609	184	(2)	12,791
3	332	Reservoirs, Dams & Waterways	26,644	630	(10)	27,265
4	333	Water Wheels, Turbines and Gen.	73,448	9,944	(262)	83,130
5	334	Accessory Equipment	32,934	5,568	(379)	38,123
6	335	Other Power Plant Equipment	41,642	18,720	(7)	60,354
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			189,525	35,046	(659)	223,912
9		**Transmission Plant**				
10	350	Land Rights-R/W	7,271	176	-	7,447
11	350.1	Land Rights-Clearing	6,236	176	-	6,412
12	353	Station Equipment	150,925	67,941	(77)	218,789
13	355	Poles Towers & Fixtures	89,033	2,031	(3,693)	87,371
14	356	Conductors and Devices	86,903	(9,103)	(3,664)	74,135
15	359	Roads and Trails	1,121	-	-	1,121
16			341,489	61,221	(7,434)	395,276
17		**Distribution Plant**				
18	360	Land Rights-R/W	2,689	916	-	3,605
19	360.1	Land Rights-Clearing	9,964	916	-	10,879
20	362	Station Equipment	199,086	557	(446)	199,197
21	364	Poles Towers & Fixtures	137,498	8,729	(398)	145,829
22	365	Conductors and Devices	224,957	8,132	(770)	232,319
23	368	Line Transformers	104,732	2,609	(1,384)	105,958
24	369	Services	7,292	3,494	-	10,786
25	370	Meters	13,593	916	(210)	14,299
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	11,485	-	(47)	11,438
28			712,234	26,267	(3,255)	735,247
29		**General Plant**				
30	389	Land	12,093	-	-	12,093
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	27,045	3,525	-	30,570
33	391	Office Furniture & Equipment	5,729	182	-	5,912
34	391.1	Computer Equipment	62,875	6,973	(111)	69,737
35	392	Transportation Equipment	17,755	3,527	(729)	20,554
36	394	Tools and Work Equipment	11,296	1,692	(68)	12,920
37	397	Communication Structures and Equipment	23,238	3,542	-	26,780
38			160,368	19,441	(908)	178,902
39						
40	101	**Plant in Service**	1,403,617	141,975	(12,256)	1,533,336
41	107.1	Plant under construction not subject				
42		to AFUDC	7,213			6,237
43	107.2	Plant under construction				
44		subject to AFUDC	50,769			5,005
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,473,511			1,556,491

Note: Minor differences due to rounding

TABLE 1 – A – UTILITY PLANT IN SERVICE (2012)

Line	Account		December 31 2011	Additions	Retirements	December 31 2012
		Hydraulic Production Plants		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	12,791	1,252	(2)	14,041
3	332	Reservoirs, Dams & Waterways	27,265	4,103	(10)	31,359
4	333	Water Wheels, Turbines and Gen.	83,130	3,434	(262)	86,302
5	334	Accessory Equipment	38,123	2,112	(379)	39,856
6	335	Other Power Plant Equipment	60,354	637	(7)	60,984
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			223,912	11,537	(659)	234,790
9		**Transmission Plant**				
10	350	Land Rights-R/W	7,447	200	-	7,647
11	350.1	Land Rights-Clearing	6,412	200	-	6,612
12	353	Station Equipment	218,789	21,349	(77)	240,061
13	355	Poles Towers & Fixtures	87,371	8,064	(3,693)	91,742
14	356	Conductors and Devices	74,135	5,629	(3,664)	76,099
15	359	Roads and Trails	1,121	-	-	1,121
16			395,276	35,441	(7,434)	423,283
17		**Distribution Plant**				
18	360	Land Rights-R/W	3,605	-	-	3,605
19	360.1	Land Rights-Clearing	10,879	-	-	10,879
20	362	Station Equipment	199,197	-	(446)	198,751
21	364	Poles Towers & Fixtures	145,829	25,036	(398)	170,468
22	365	Conductors and Devices	232,319	7,749	(770)	239,298
23	368	Line Transformers	105,958	3,291	(1,384)	107,865
24	369	Services	10,786	-	-	10,786
25	370	Meters	14,299	1,097	(210)	15,186
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	11,438	-	(47)	11,390
28			735,247	37,173	(3,255)	769,166
29		**General Plant**				
30	389	Land	12,093	1,033	-	13,126
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	30,570	3,398	-	33,968
33	391	Office Furniture & Equipment	5,912	121	-	6,033
34	391.1	Computer Equipment	69,737	5,950	(111)	75,576
35	392	Transportation Equipment	20,554	2,421	(729)	22,246
36	394	Tools and Work Equipment	12,920	931	(68)	13,782
37	397	Communication Structures and Equipment	26,780	240	-	27,020
38			178,902	14,094	(908)	192,088
39						
40	101	**Plant in Service**	1,533,336	98,246	(12,256)	1,619,327
41	107.1	Plant under construction not subject				
42		to AFUDC	6,237			5,875
43	107.2	Plant under construction				
44		subject to AFUDC	5,005			12,777
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,556,491			1,649,891

Note: Minor differences due to rounding

TABLE 1 – A – UTILITY PLANT IN SERVICE (2013)

Line	Account		December 31 2012	Additions	Retirements	December 31 2013
		Hydraulic Production Plants		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	14,041	966	(2)	15,005
3	332	Reservoirs, Dams & Waterways	31,359	701	(10)	32,050
4	333	Water Wheels, Turbines and Gen.	86,302	53	(262)	86,093
5	334	Accessory Equipment	39,856	417	(379)	39,893
6	335	Other Power Plant Equipment	60,984	631	(7)	61,607
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			234,790	2,766	(659)	236,897
9		**Transmission Plant**				
10	350	Land Rights-R/W	7,647	200	-	7,847
11	350.1	Land Rights-Clearing	6,612	200	-	6,812
12	353	Station Equipment	240,061	19,018	(77)	259,002
13	355	Poles Towers & Fixtures	91,742	7,276	(3,693)	95,324
14	356	Conductors and Devices	76,099	6,100	(3,664)	78,535
15	359	Roads and Trails	1,121	-	-	1,121
16			423,283	32,793	(7,434)	448,642
17		**Distribution Plant**				
18	360	Land Rights-R/W	3,605	-	-	3,605
19	360.1	Land Rights-Clearing	10,879	-	-	10,879
20	362	Station Equipment	198,751	-	(446)	198,305
21	364	Poles Towers & Fixtures	170,468	23,650	(398)	193,721
22	365	Conductors and Devices	239,298	7,004	(770)	245,532
23	368	Line Transformers	107,865	3,208	(1,384)	109,689
24	369	Services	10,786	0	-	10,786
25	370	Meters	15,186	1,069	(210)	16,046
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	11,390	-	(47)	11,343
28			769,166	34,932	(3,255)	800,843
29		**General Plant**				
30	389	Land	13,126	2,500	-	15,626
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	33,968	24,069	-	58,037
33	391	Office Furniture & Equipment	6,033	122	-	6,155
34	391.1	Computer Equipment	75,576	14,702	(111)	90,167
35	392	Transportation Equipment	22,246	2,436	(729)	23,953
36	394	Tools and Work Equipment	13,782	863	(68)	14,577
37	397	Communication Structures and Equipment	27,020	23,005	-	50,025
38			192,088	67,697	(908)	258,877
39						
40	101	**Plant in Service**	1,619,327	138,188	(12,256)	1,745,259
41	107.1	Plant under construction not subject				
42		to AFUDC	5,875			5,875
43	107.2	Plant under construction				
44		subject to AFUDC	12,777			4,440
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,649,891			1,767,486

Note: Minor differences due to rounding

TABLE 1 – A – 1 – ADDITIONS TO PLANT IN SERVICE (2011)

		CWIP Dec 31, 2010	Expenditures 2011	CWIP Dec 31, 2011	Additions to Plant in Service
		($000s)			
Hydraulic Production					
1	Upper Bonnington Spill Gate Rebuild	3	621	624	-
2	Lower Bonnington Power House Windows	8	354	362	-
3	South Slocan Unit 1 Life Extension	-	79	-	79
4	Corra Linn Unit 1 Life Extension	13,010	3,055	-	16,065
5	Corra Linn Unit 2 Life Extension	3,265	12,748	560	15,453
6	All Plants Station Service	78	1,352	150	1,280
7	Lower & Upper Bonnington Plant Totalizer Upgrade	-	89	-	89
8	South Slocan Plant Automation	-	251	-	251
9	South Slocan Fire Panel	-	274	-	274
10	Lower & Upper Bonnington Communication Network	343	43	-	386
11	Upper Bonnington Extension Trash Rack Gantry Replacement	204	166	-	371
12	South Slocan Domestic Water Supply Ph.3	86	39	-	125
13	Queen's Bay Level Gauge Building Ph.1	18	21	-	39
14	All Plants Minor Sustainment	-	634	-	634
15		**17,015**	**19,726**	**1,696**	**35,046**
Transmission Plant					
16	Okanagan Transmission Reinforcement	32,744	15,692	1,968	46,468
17	Ellison to Sexsmith Transmission Tie	-	693	693	-
18	Huth Bus Reconfiguration	241	4,992	-	5,233
19	Benvoulin Distribution Source	-	928	-	928
20	Capitalized Inventory	5,333	542	5,875	-
21	Recreation Capacity Increase Stages 1,2,3	-	(23)	-	(23)
22	30 Line Conversion Slocan & Coffee Creek Substations	-	337	-	337
23	Transmission Sustainment	84	2,545	-	2,629
24	Station Sustainment	563	5,226	-	5,789
25		**38,965**	**30,933**	**8,537**	**61,361**
Distribution Plant					
26	New Connects System Wide	-	15,969	-	15,969
27	Distribution Unplanned Growth Projects	-	986	-	986
28	Distrlbution Sustainment	108	9,467	-	9,575
29		**108**	**26,422**	**-**	**26,530**
General Plant					
30	Distribution Station Automation	579	2,127	-	2,706
31	Mandatory Reliability Standards Compliance	738	600	-	1,338
32	Communications Upgrades	192	2,138	-	2,330
33	Kootenay Long Term Facility Strategy	-	503	503	-
34	Okanagan Long Term Solution	-	507	507	-
35	Information Systems	-	4,682	-	4,682
36	Vehicles	386	2,738	-	3,124
37	Metering Changes	-	472	-	472
38	Telecommunications	-	368	-	368
39	Buildings	-	1,288	-	1,288
40	Furniture & Fixtures	-	182	-	182
41	Tools & Equipment	-	622	-	622
42	PCB Environmental Compliance	-	1,926	-	1,926
43		**1,895**	**18,154**	**1,010**	**19,038**
44					
45	**TOTAL**	**57,982**	**95,235**	**11,242**	**141,975**

Note: Minor differences due to rounding

TABLE 1 – A – 1 – ADDITIONS TO PLANT IN SERVICE (2012)

		CWIP Dec. 31, 2011	Expenditures 2012	CWIP Dec 31, 2012	Additions to Plant in Service
		($000s)			
	Hydraulic Production				
1	All Plants Concrete and Structural Rehabilitation	-	495	-	495
2	Upper Bonnington Spillgate Rebuild	624	1,061	-	1,685
3	Lower Bonnington Power House Windows	362	366	-	728
4	Corra Linn Unit 2 Life Extension	560	3,423	-	3,983
5	All Plants Station Service	150	672	-	822
6	Lower & Upper Bonnington Plant Totalizer Upgrade	-	90	-	90
7	Corra Linn Unit 3 Completion	-	675	-	675
8	Upper Bonnington Old Plant Various Unit Upgrades	-	1,277	-	1,277
9	Lower & Upper Bonnington & Corra Linn Fire Panels	-	250	-	250
10	All Plants Safety & Security	-	471	-	471
11	All Plants Minor Sustainment	-	1,061	-	1,061
12		**1,696**	**9,841**	**-**	**11,537**
	Transmission Plant				
13	Okanagan Transmission Reinforcement	1,968	2,219	-	4,187
14	Ellison to Sexsmith Transmission Tie	693	6,825	-	7,518
15	Grand Forks Transformer Addition	-	2,491	2,491	-
16	Transmission Sustainment	-	8,493	-	8,493
17	Environmental Compliance (PCB Mitigation)	-	10,749	-	10,749
18	Other Station Sustainment	-	3,269	-	3,269
19	Kelowna 138kV Loop Fibre Installation	-	1,212	-	1,212
20	Communications Upgrades	-	13	-	13
21	Capitalized Inventory	5,875	-	5,875	-
22		**8,537**	**35,271**	**8,366**	**35,441**
	Distribution Plant				
23	New Connects System Wide	-	21,942	-	21,942
24	Small Growth Projects	-	1,059	-	1,059
25	Distribution Unplanned Growth Projects	-	826	-	826
26	Glenmerry Feeder 2 to Glenmerry Feeder 3 Tie Line	-	593	-	593
27	Distribution Sustainment	-	12,753	-	12,753
28		**-**	**37,173**	**-**	**37,173**
	General Plant				
29	Communications Upgrades	-	397	-	397
30	Kootenay Long Term Facility Strategy	503	6,020	5,209	1,314
31	Okanagan Long Term Solution	507	69	576	-
32	Central Warehousing	-	1,755	-	1,755
33	Advanced Metering Infrastructure	-	4,501	4,501	-
34	Information Systems	-	5,672	-	5,672
35	Vehicles	-	2,421	-	2,421
36	Metering Changes	-	403	-	403
37	Telecommunications	-	121	-	121
38	Buildings	-	1,362	-	1,362
39	Furniture & Fixtures	-	121	-	121
40	Tools & Equipment	-	528	-	528
41		**1,010**	**23,370**	**10,286**	**14,094**
42					
43	**TOTAL**	**11,242**	**105,656**	**18,652**	**98,246**

Note: Minor differences due to rounding

TABLE 1 – A – 1 – ADDITIONS TO PLANT IN SERVICE (2013)

		CWIP Dec. 31, 2012	Expenditures 2013	CWIP Dec 31, 2013	Additions to Plant in Service
			($000s)		
Hydraulic Production					
1	All Plants Concrete and Structural Rehabilitation	-	543	-	543
2	Lower Bonnington Power House Windows	-	8	-	8
3	Upper Bonnington, South Slocan & Corra Linn Power House Windows	-	430	-	430
4	Lower & Upper Bonnington & Corra Linn Fire Panels	-	259	-	259
5	All Plants Safety & Security	-	475	-	475
6	All Plants Minor Sustainment	-	1,051	-	1,051
7		**-**	**2,766**	**-**	**2,766**
Transmission Plant					
8	Ellison to Sexsmith Transmission Tie	-	413	-	413
9	Grand Forks Transformer Addition	2,491	4,714	-	7,205
10	Kelowna Bulk Transformer Capacity Addition	-	3,720	3,720	-
11	Transmission Sustainment	-	8,218	-	8,218
12	Environmental Compliance (PCB Mitigation)	-	11,022	-	11,022
13	Other Station Sustainment	-	3,455	69	3,386
14	Kelowna 138kV Loop Fibre Installation	-	2,549	-	2,549
15	Capitalized Inventory	5,875	-	5,875	-
16		**8,366**	**34,091**	**9,664**	**32,793**
Distribution Plant					
17	New Connects System Wide	-	21,388	-	21,388
18	Small Growth Projects	-	852	-	852
19	Distribution Unplanned Growth Projects	-	831	-	831
20	Ellison Feeder 2 to Sexsmith Feeder 1 Tie	-	1,102	-	1,102
21	Distribution Sustainment	-	10,759	-	10,759
22		**-**	**34,932**	**-**	**34,932**
General Plant					
23	Communications Upgrades	-	400	-	400
24	Kootenay Long Term Facility Strategy	5,209	10,477	-	15,686
25	Trail Office Lease Purchase	-	10,000	-	10,000
26	Okanagan Long Term Solution	576	75	651	-
27	Advanced Metering Infrastructure	4,501	27,931	-	32,432
28	Information Systems	-	4,692	-	4,692
29	Vehicles	-	2,436	-	2,436
30	Metering Changes	-	406	-	406
31	Telecommunications	-	183	-	183
32	Buildings	-	883	-	883
33	Furniture & Fixtures	-	122	-	122
34	Tools & Equipment	-	457	-	457
35		**10,286**	**58,062**	**651**	**67,697**
36					
37	**TOTAL**	**18,652**	**129,851**	**10,315**	**138,188**

Note: Minor differences due to rounding

TABLE 1 – B – DEFERRED CHARGES AND CREDITS (2011)

		Balance at Dec. 31, 2010	Additions and Transfers	Amort / Transfr to Other Accounts	Amortization	Balance at Dec. 31, 2011
				($000s)		
1	**Demand Side Management**					
2	Demand Side Management Additions	20,961	7,341	-	(1,859)	26,444
3	Tax Impact	(12,528)	(1,945)	-	493	(13,981)
4		**8,433**	**5,396**	**-**	**(1,366)**	**12,463**
5	**Preliminary and Investigative Charges**					
6	Long Term Facilities Strategy 2008	142	-	(142)	-	-
7	Pumped Storage Hydro	227	-	-	-	227
8	PCB Environmental Compliance	136	-	(136)	-	-
9	2012 Integrated System Plan	1,748	1,638	-	-	3,386
10	2011 Capital Expenditure Plan	182	-	(182)	-	-
11	P1 - P4 Sustainment Capital	-	25	-	-	25
12	Kelowna Bulk Transformer Capacity Addition	-	173	-	-	173
13		**2,435**	**1,836**	**(460)**	**-**	**3,811**
14	**Deferred Regulatory Expense**					
15	2009 Flow-Through and ROE Sharing Mechanism Adjustments	(1,090)	-	1,090	-	-
16	2010 Flow-Through and ROE Sharing Mechanism Adjustments	(2,061)	-	1,681	-	(380)
17	2011 Flow-Through and ROE Sharing Mechanism Adjustments	-	(5,036)	-	-	(5,036)
18	Implementation of New Rate Structures	-	25	-	-	25
19	Tax Impact	-	(7)	-	-	(7)
20	Shaw Application for Transmission Facility Access	288	37	-	-	325
21	Tax Impact	(82)	(10)	-	-	(92)
22	Tariff Amendment - Adaptive Street Lighting	3	-	(3)	-	-
23	Tax Impact	(1)	-	1	-	-
24	Residential Inclining Block Rate and Industrial Stepped Rate Applications	-	100	-	-	100
25	Tax Impact	-	(27)	-	-	(27)
26	Irrigation Rate Payer Group Consultation and Load Research	-	100	-	-	100
27	Tax Impact	-	(27)	-	-	(27)
28	2010 Revenue Requirements	75	-	-	(75)	-
29	Tax Impact	(22)	-	-	22	-
30	2011 Revenue Requirements	35	40	-	-	75
31	Tax Impact	(10)	(11)	-	-	(21)
32	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	360	-	-	(120)	240
33	Tax Impact	(103)	-	-	34	(68)
34	Cost of Service Analysis and Rate Design Application	1,708	395	-	(526)	1,577
35	Tax Impact	(503)	(105)	-	152	(455)
36	BC Hydro Amendment to 3808 (PPA) Proceedings	76	-	-	(38)	38
37	Tax Impact	(23)	-	-	12	(12)
38	Section-5 Provincial Transmission Inquiry	90	-	-	(90)	-
39	Tax Impact	(27)	-	-	27	-
40	Renewal of BCH Power Purchase Agreement	109	200	-	-	309
41	Tax Impact	(33)	(53)	-	-	(86)
42	2012 Integrated System Plan and 2012 - 2013 Revenue Requirements	864	2,425	-	-	3,289
43	Tax Impact	(266)	(643)	-	-	(908)
44	BC Hydro Waneta Transaction Application	284	-	-	(95)	189
45	Tax Impact	(85)	-	-	28	(57)
46	FortisBC Energy (Terasen Gas) ROE and Capital Structure Application	76	-	-	(76)	-
47	Tax Impact	(23)	-	-	23	-
48		**(358)**	**(2,594)**	**2,768**	**(722)**	**(906)**

TABLE 1 – B – DEFERRED CHARGES AND CREDITS (2011) CONT'D

		Balance at Dec. 31, 2010	Additions and Transfers	Amort / Transfr to Other Accounts	Amortization	Balance at Dec. 31, 2011
				($000s)		
49	**Other Deferred Charges and Credits**					
50	Trail Office Lease Costs	155	-	-	(12)	143
51	Trail Office Rental to SD20	(729)	-	(57)	-	(786)
52	Prepaid Pension Costs	7,448	596	-	-	8,044
53	Tax Impact	(757)	(158)	-	-	(915)
54	Other Post Employment Benefit (OPEB)	(10,321)	(2,803)	-	-	(13,124)
55	Tax Impact	3,211	743	-	-	3,954
56	Revenue Protection	221	235	-	(221)	235
57	Tax Impact	(63)	(62)	-	63	(62)
58	Princeton Light and Power Computer Software	40	-	-	(23)	16
59	Princeton Light and Power Deferred Pension Credit	(46)	-	-	12	(35)
60	Right of Way Reclamation (Pine Beetle Kill)	2,006		-	(251)	1,755
61	Tax Impact	(622)	-	-	78	(544)
62	International Financial Reporting Standards	214	-	-	(214)	-
63	Tax Impact	(61)	-	-	61	-
64	Right of Way Encroachment Litigation	91	29	-	-	120
65	Tax Impact	(28)	(8)	-	-	(35)
66	Harmonized Sales Tax Implementation Project	222	-	-	(222)	-
67	Tax Impact	(63)	-	-	63	-
68	Demand Side Management Study	259	-	-	(86)	173
69	Tax Impact	(75)	-	-	25	(50)
70	US Generally Accepted Accounting Principles	-	808	-	-	808
71	Tax Impact	-	(214)	-	-	(214)
72	Joint Pole Use Audit 2008	93	-	-	(31)	62
73	Tax Impact	(28)	-	-	9	(19)
74	Pope & Talbot Litigation	23			(23)	-
75	Tax Impact	(7)			7	-
76	Mandatory Reliability Standards	848	152	-	-	1,000
77	Tax Impact	(242)	(40)	-	-	(282)
78		**1,788**	**(722)**	**(57)**	**(766)**	**243**
79	**Deferred Debt Issue Costs**					
80	Series F	70	-	-	(39)	31
81	Series G	93	-	-	(7)	86
82	Series H	67	-	-	(13)	54
83	Series I	157	-	-	(14)	142
84	Series 04-1	858	-	-	(219)	638
85	Tax Impact	(61)	-	-	16	(45)
86	Series 05-1	1,032	-	-	(42)	990
87	Tax Impact	(376)	-	-	15	(361)
88	Series 07-1	1,153	-	-	(32)	1,121
89	Tax Impact	(320)	(88)	-	9	(400)
90	MTN-2009	957	-	-	(34)	924
91	Tax Impact	(118)	(59)	-	4	(173)
92	MTN-2010	941	(38)	-	(23)	881
93	Tax Impact	(54)	(39)	-	1	(91)
94		**4,399**	**(224)**	**-**	**(378)**	**3,797**
95						
96	**TOTAL DEFERRED CHARGES (RATE BASE)**	**16,698**	**3,691**	**2,251**	**(3,233)**	**19,408**
97	**Total Deferred Charges (Non Rate Base)**					
98						
99	Advanced Metering Infrastructure Project (1)	920	881	-		1,801
100	Tax Impact	-	-	-		-
101	**GRAND TOTAL DEFERRED CHARGES**	**17,618**	**4,572**	**2,251**	**(3,233)**	**21,209**

Note (1): Pursuant to the Negotiated Settlement Agreements for 2010 and 2011 Revenue Requirements, AMI costs are being collected in a non-rate base deferral account that will collect AFUDC.

Note: Minor differences due to rounding

TABLE 1 – B – DEFERRED CHARGES AND CREDITS (2012)

		Balance at Dec. 31, 2011	Additions and Transfers	Amort / Transfr to Other	Amortization	Balance at Dec. 31, 2012
				($000s)		
1	**Demand Side Management**					
2	Demand Side Management Additions	26,444	7,731	-	(2,361)	31,813
3	Tax Impact	(13,981)	(1,933)	-	590	(15,323)
4		**12,463**	**5,798**	**-**	**(1,771)**	**16,490**
5	**Preliminary and Investigative Charges**					
6	Pumped Storage Hydro	227	-	-	-	227
7	2012 Integrated System Plan	3,386	-	(677)	-	2,709
8	P1 - P4 Sustainment Capital	25	25	(25)	-	25
9	Kelowna Bulk Transformer Capacity Addition	173	100	-	-	273
10	Advanced Metering Infrastructure Project	-	1,812	(1,812)	-	-
11		**3,811**	**1,937**	**(2,514)**	**-**	**3,234**
12	**Non-Controllable Items Variances**					
13	Power Purchase Variance	-	-	-	-	-
14	Tax Impact	-	-	-	-	-
15	Revenue Variance	-	-	-	-	-
16	Tax Impact	-	-	-	-	-
17	Income Tax Variance	-	-	-	-	-
18	Tax Impact	-	-	-	-	-
19	HST Removal or Reform	-	-	-	-	-
20	Tax Impact	-	-	-	-	-
21	Property Tax Asset Valuation Review	-	-	-	-	-
22	Tax Impact	-	-	-	-	-
23	Interest Expense Variance	-	-	-	-	-
24	Tax Impact	-	-	-	-	-
25	Pension and Other Post Employment Benefits Expense Variance	-	-	-	-	-
26	Tax Impact	-	-	-	-	-
27	Insurance Expense Variance	-	-	-	-	-
28	Tax Impact	-	-	-	-	-
29	Extraordinary Costs Variance	-	-	-	-	-
30	Tax Impact	-	-	-	-	-
31		-	-	-	-	-
32	**Deferred Regulatory Expense**					
33	2010 Flow-Through and ROE Sharing Mechanism Adjustments	(380)	-	380	-	-
34	2011 Flow-Through and ROE Sharing Mechanism Adjustments	(5,036)	-	5,036	-	-
35	Implementation of New Rate Structures	25	-	-	(25)	-
36	Tax Impact	(7)	-	-	7	-
37	Shaw Application for Transmission Facility Access	325	-	-	(325)	-
38	Tax Impact	(92)	-	-	92	-
39	Residential Inclining Block Rate and Industrial Stepped Rate Applications	100	-	-	(100)	-
40	Tax Impact	(27)	-	-	27	-
41	Irrigation Rate Payer Group Consultation and Load Research	100	-	-	-	100
42	Tax Impact	(27)	-	-	-	(27)
43	2011 Revenue Requirements	75	-	-	(75)	-
44	Tax Impact	(21)	-	-	21	-
45	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	240	-	-	(120)	120
46	Tax Impact	(68)	-	-	34	(34)
47	Cost of Service Analysis and Rate Design Application	1,577	-	-	(526)	1,052
48	Tax Impact	(455)	-	-	152	(304)
49	BC Hydro Amendment to 3808 (PPA) Proceedings	38	-	-	(38)	-
50	Tax Impact	(12)	-	-	12	-
51	Renewal of BCH Power Purchase Agreement	309	-	-	(62)	247
52	Tax Impact	(86)	-	-	17	(69)
53	2012 Integrated System Plan and 2012 - 2013 Revenue Requirements	3,289	-	-	(658)	2,631
54	Tax Impact	(908)	-	-	182	(727)
55	BC Hydro Waneta Transaction Application	189	-	-	(95)	95
56	Tax Impact	(57)	-	-	28	(28)
57		**(906)**	**-**	**5,416**	**(1,453)**	**3,057**

TABLE 1 – B – DEFERRED CHARGES AND CREDITS (2012) CONT'D

		Balance at Dec. 31, 2011	Additions and Transfers	Amort / Transfr to Other	Amortization	Balance at Dec. 31, 2012
				($000s)		
58	**Other Deferred Charges and Credits**					
59	Trail Office Lease Costs	143	-	-	(12)	131
60	Trail Office Rental to SD20	(786)	-	(65)	-	(851)
61	Prepaid Pension Costs	8,044	987	-		9,031
62	Tax Impact	(915)	(247)	-	(46)	(1,208)
63	Other Post Employment Benefit (OPEB)	(13,124)	(7,663)	-	-	(20,787)
64	Tax Impact	3,954	1,916	-	(161)	5,709
65	US GAAP Pension Transitional Obligation	-	2,194	(183)	-	2,011
66	Tax Impact	-	(549)	-	46	(503)
67	US GAAP OPEB Transitional Obligation	-	5,488	(644)	-	4,844
68	Tax Impact	-	(1,372)	-	161	(1,211)
69	Revenue Protection	235	-	-	(235)	-
70	Tax Impact	(62)	-	-	62	-
71	Princeton Light and Power Computer Software	16	-	-	(10)	6
72	Princeton Light and Power Deferred Pension Credit	(35)	-	-	12	(23)
73	Right of Way Reclamation (Pine Beetle Kill)	1,755	-	-	(251)	1,504
74	Tax Impact	(544)	-	-	78	(466)
75	Right of Way Encroachment Litigation	120	-	-	-	120
76	Tax Impact	(35)	-	-	-	(35)
77	Asset Management	-	520	-	-	520
78	Tax Impact	-	(130)	-	-	(130)
79	Demand Side Management Study	173	-	-	(86)	86
80	Tax Impact	(50)	-	-	25	(25)
81	US Generally Accepted Accounting Principles	808		-	(404)	404
82	Tax Impact	(214)	-	-	107	(107)
83	Joint Pole Use Audit 2008	62	-	-	(31)	31
84	Tax Impact	(19)	-	-	9	(9)
85	Mandatory Reliability Standards	1,000	-	-	(200)	800
86	Tax Impact	(282)	-	-	56	(226)
87		**243**	**1,145**	**(892)**	**(880)**	**(384)**
88	**Deferred Debt Issue Costs**					
89	Series F	31	-	-	(31)	-
90	Series G	86	-	-	(7)	78
91	Series H	54	-	-	(13)	41
92	Series I	142	-	-	(14)	128
93	Series 04-1	638	-	-	(219)	419
94	Tax Impact	(45)	-	-	16	(30)
95	Series 05-1	990	-	-	(42)	949
96	Tax Impact	(361)	-	-	15	(346)
97	Series 07-1	1,121	-	-	(32)	1,090
98	Tax Impact	(400)	-	-	11	(389)
99	MTN-2009	924	-	-	(34)	890
100	Tax Impact	(173)	(59)	-	6	(226)
101	MTN-2010	881	-	-	(23)	858
102	Tax Impact	(91)	(39)	-	2	(128)
103		**3,797**	**(98)**	**-**	**(364)**	**3,335**
104						
105	**TOTAL DEFERRED CHARGES (RATE BASE)**	**19,408**	**8,782**	**2,010**	**(4,468)**	**25,731**
106	**Total Deferred Charges (Non Rate Base)**					
107	Advanced Metering Infrastructure Project (1)	1,801	11	(1,812)		-
108	**GRAND TOTAL DEFERRED CHARGES**	**21,209**	**8,793**	**198**	**(4,468)**	**25,731**

Note (1): Pursuant to the NSA for 2010 and 2011 Revenue Requirements, AMI costs are being collected in a non-rate base deferral account that will collect AFUDC and will be transferred to Preliminary Investigative Charges in 2012, then eventually transferred to capital, once the Capital Project commences in 2013.

Note: Minor differences due to rounding

TABLE 1 – B – DEFERRED CHARGES AND CREDITS (2013)

		Balance at Dec. 31, 2012	Additions and Transfers	Amort / Transfr to Other	Amortization	Balance at Dec. 31, 2013
				($000s)		
1	**Demand Side Management**					
2	Demand Side Management Additions	31,813	7,878	-	(2,905)	36,786
3	Tax Impact	(15,323)	(1,970)	-	726	(16,567)
4		**16,490**	**5,909**	**-**	**(2,179)**	**20,220**
5	**Preliminary and Investigative Charges**					
6	Pumped Storage Hydro	227	-	-	-	227
7	2012 Integrated System Plan	2,709	-	(677)	-	2,032
8	P1 - P4 Sustainment Capital	25	25	(25)	-	25
9	Kelowna Bulk Transformer Capacity Addition	273	-	(273)	-	-
10	2014 - 2015 Capital Expenditure Plan	-	750	-	-	750
11		**3,234**	**775**	**(975)**	**-**	**3,034**
12	**Non-Controllable Items Variances**					
13	Power Purchase Variance	-	-	-	-	-
14	Tax Impact	-	-	-	-	-
15	Revenue Variance	-	-	-	-	-
16	Tax Impact	-	-	-	-	-
17	Income Tax Variance	-	-	-	-	-
18	Tax Impact	-	-	-	-	-
19	HST Removal or Reform	-	-	-	-	-
20	Tax Impact	-	-	-	-	-
21	Property Tax Asset Valuation Review	-	-	-	-	-
22	Tax Impact	-	-	-	-	-
23	Interest Expense Variance	-	-	-	-	-
24	Tax Impact	-	-	-	-	-
25	Pension and Other Post Employment Benefits Expense Variance	-	-	-	-	-
26	Tax Impact	-	-	-	-	-
27	Insurance Expense Variance	-	-	-	-	-
28	Tax Impact	-	-	-	-	-
29	Extraordinary Costs Variance	-	-	-	-	-
30	Tax Impact	-	-	-	-	-
31		-	-	-	-	-
32	**Deferred Regulatory Expense**					
33	Irrigation Rate Payer Group Consultation and Load Research	100	-	-	(100)	-
34	Tax Impact	(27)	-	-	27	-
35	2014 Revenue Requirements	-	100	-	-	100
36	Tax Impact	-	(25)	-	-	(25)
37	2014 - 2015 Capital Expenditure Plan	-	100	-	-	100
38	Tax Impact	-	(25)	-	-	(25)
39	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	120	-	-	(120)	-
40	Tax Impact	(34)	-	-	34	-
41	Cost of Service Analysis and Rate Design Application	1,052	-	-	(526)	526
42	Tax Impact	(304)	-	-	152	(152)
43	Renewal of BCH Power Purchase Agreement	247	-	-	(62)	185
44	Tax Impact	(69)	-	-	17	(52)
45	2012 Integrated System Plan and 2012 - 2013 Revenue Requirements	2,631	-	-	(658)	1,974
46	Tax Impact	(727)	-	-	182	(545)
47	BC Hydro Waneta Transaction Application	95	-	-	(95)	-
48	Tax Impact	(28)	-	-	28	-
49		**3,057**	**150**	**-**	**(1,121)**	**2,086**

TABLE 1 – B – DEFERRED CHARGES AND CREDITS (2013) CONT'D

		Balance at Dec. 31, 2012	Additions and Transfers	Amort / Transfr to Other	Amortization	Balance at Dec. 31, 2013
				($000s)		
50	**Other Deferred Charges and Credits**					
51	Trail Office Lease Costs	131	-	(131)	-	-
52	Trail Office Rental to SD20	(851)	-	851	-	-
53	Prepaid Pension Costs	9,031	3,551	-	-	12,582
54	Tax Impact	(1,208)	(888)	-	(46)	(2,142)
55	Other Post Employment Benefit (OPEB)	(20,787)	(2,246)	-	-	(23,033)
56	Tax Impact	5,709	562	-	(161)	6,109
57	US GAAP Pension Transitional Obligation	2,011	-	(183)	-	1,828
58	Tax Impact	(503)	-	-	46	(457)
59	US GAAP OPEB Transitional Obligation	4,844	-	(644)	-	4,200
60	Tax Impact	(1,211)	-	-	161	(1,050)
61	Princeton Light and Power Computer Software	6	-	-	(6)	-
62	Princeton Light and Power Deferred Pension Credit	(23)	-	-	12	(12)
63	Right of Way Reclamation (Pine Beetle Kill)	1,504	-	-	(251)	1,254
64	Tax Impact	(466)	-	-	78	(389)
65	Right of Way Encroachment Litigation	120	-	-	-	120
66	Tax Impact	(35)	-	-	-	(35)
67	Asset Management	520	265	-	-	785
68	Tax Impact	(130)	(66)	-	-	(196)
69	Demand Side Management Study	86	-	-	(86)	-
70	Tax Impact	(25)	-	-	25	-
71	US Generally Accepted Accounting Principles	404		-	(404)	-
72	Tax Impact	(107)	-	-	107	-
73	Joint Pole Use Audit 2008	31	-	-	(31)	-
74	Tax Impact	(9)	-	-	9	-
75	Joint Pole Use Audit 2013	-	250	-	(50)	200
76	Tax Impact	-	(63)	-	13	(50)
77	Mandatory Reliability Standards	800	-	-	(200)	600
78	Tax Impact	(226)	-		56	(169)
79		**(384)**	**1,365**	**(107)**	**(729)**	**145**
80	**Deferred Debt Issue Costs**					
81	Series G	78	-	-	(7)	71
82	Series H	41	-	-	(13)	28
83	Series I	128	-	-	(14)	114
84	Series 04-1	419	-	-	(219)	200
85	Tax Impact	(30)	-	-	16	(14)
86	Series 05-1	949	-	-	(42)	907
87	Tax Impact	(346)	-	-	15	(331)
88	Series 07-1	1,090	-	-	(32)	1,058
89	Tax Impact	(389)	-	-	11	(377)
90	MTN-2009	890	-	-	(34)	856
91	Tax Impact	(226)	(59)	-	9	(277)
92	MTN-2010	858	-	-	(23)	835
93	Tax Impact	(128)	(39)	-	3	(163)
94	Series 13-1	-	1,587	-	-	1,587
95	Tax Impact	-	(79)	-	-	(79)
96		**3,335**	**1,410**	**-**	**(330)**	**4,414**
97						
98	**TOTAL DEFERRED CHARGES (RATE BASE)**	**25,731**	**9,608**	**(1,082)**	**(4,358)**	**29,899**

Note: Minor differences due to rounding

TABLE 1 – C – ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (2011)

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2010	Deprec. Rate	Asset Balance Dec. 31, 2010	Depreciation Expense Dec. 31, 2011	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2011
					($000s)			
		Hydraulic Production Plant						
1	330	Land Rights	(570)	2.6%	962	25	-	(545)
2	331	Structures and Improvements	5,343	1.2%	12,609	157	(7)	5,493
3	332	Reservoirs, Dams and Waterways	5,535	1.7%	26,644	453	(28)	5,960
4	333	Water Wheels, Turbines & Generators	1,608	2.2%	73,448	1,617	(561)	2,664
5	334	Accessory Electrical Equipment	7,613	2.4%	32,934	787	(546)	7,854
6	335	Other Power Plant Equipment	9,219	2.3%	41,642	965	(570)	9,614
7	336	Roads, Railroads, and Bridges	486	1.4%	1,287	18	-	504
8			29,233	2.1%	189,525	4,023	(1,713)	31,543
9		Transmission Plant						
10	350	Land Rights - R/W	(62)	0.0%	7,271	-	-	(62)
11	350.1	Land Rights - Clearing	2,062	1.6%	6,236	100	-	2,162
12	353	Station Equipment	2,323	3.0%	150,925	4,530	(2,341)	4,512
13	355	Poles Towers & Fixtures	8,318	3.0%	89,033	2,672	(3,761)	7,229
14	356	Conductors and Devices	4,651	3.0%	86,903	2,608	(3,361)	3,898
15	359	Roads and Trails	89	2.9%	1,121	33	-	122
16			17,381	2.9%	341,489	9,943	(9,463)	17,861
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	2,689	-	-	(868)
19	360.1	Land Rights - Clearing	(28)	2.1%	9,964	209	-	181
20	362	Station Equipment	68,899	3.0%	199,086	5,975	(475)	74,399
21	364	Poles Towers & Fixtures	40,730	3.0%	137,498	4,127	(856)	44,000
22	365	Conductors and Devices	62,546	3.0%	224,957	6,752	(1,197)	68,100
23	368	Line Transformers	20,076	2.9%	104,732	3,038	(1,521)	21,593
24	369	Services	6,511	0.0%	7,292	-	(184)	6,328
25	370	Meters	5,294	3.5%	13,593	473	(258)	5,509
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	3,464	2.4%	11,485	276	(47)	3,692
28			203,212	2.9%	712,234	20,850	(4,539)	219,523
29		General Plant						
30	389	Land	897	0.0%	12,093	-	-	897
31	390	Structures - Frame & Iron	536	0.8%	337	3	(270)	269
32	390.1	Structures - Masonry	4,194	3.0%	22,249	665	211	5,070
33	391	Office Furniture & Equipment	4,241	7.5%	5,729	430	(3)	4,668
34	391.1	Computer Equipment	41,529	10.6%	62,875	6,689	(227)	47,990
35	392	Transportation Equipment	1,484	0.4%	17,755	71	(788)	767
36	394	Tools and Work Equipment	7,211	9.5%	11,296	1,073	(97)	8,188
37	397	Communication Structures and Equipment	7,288	6.0%	23,238	1,395	(59)	8,623
38			67,381	6.6%	155,572	10,326	(1,234)	76,473
39								
40	108	Total Accumulated Depreciation	317,207	3.2%	1,398,821	45,142	(16,949)	345,400
41								
42		Deduct - Portion of CIAC Depreciated				(4,092)		
43								
44	403	Depreciation Expense				41,050		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	5,024		11,912	186		5,210
48	390	Leasehold Improvements	2,526		4,796	571		3,097
49		Rate Stabilization Adjustment	(1,554)			311		(1,243)
50		Total Accumulated Amortization	5,996			1,068		7,064
51								
52		Accumulated Amortization per						
53		Balance Sheet	323,203			42,118		352,464

Note: Minor differences due to rounding

TABLE 1 – C – ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (2012)

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2011	Deprec. Rate	Asset Balance Dec. 31, 2011	Depreciation Expense Dec. 31, 2012	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2012
						($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(545)	3.8%	962	37	-	(508)
2	331	Structures and Improvements	5,493	1.3%	12,791	165	(33)	5,625
3	332	Reservoirs, Dams and Waterways	5,960	2.0%	27,265	548	(113)	6,395
4	333	Water Wheels, Turbines & Generators	2,664	2.0%	83,130	1,621	(348)	3,937
5	334	Accessory Electrical Equipment	7,854	2.4%	38,123	900	(432)	8,322
6	335	Other Power Plant Equipment	9,614	2.3%	60,354	1,400	(23)	10,991
7	336	Roads, Railroads, and Bridges	504	1.5%	1,287	19	-	523
8			31,543	2.1%	223,912	4,690	(949)	35,284
9		Transmission Plant						
10	350	Land Rights - R/W	(62)	0.0%	7,447	-	-	(62)
11	350.1	Land Rights - Clearing	2,162	1.5%	6,412	94	-	2,256
12	353	Station Equipment	4,512	3.4%	218,789	7,526	(1,243)	10,795
13	355	Poles Towers & Fixtures	7,229	2.6%	87,371	2,307	(4,134)	5,402
14	356	Conductors and Devices	3,898	2.1%	74,135	1,520	(3,972)	1,446
15	359	Roads and Trails	122	2.7%	1,121	30	-	152
16			17,861	2.9%	395,276	11,477	(9,349)	19,989
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	3,605	-	-	(868)
19	360.1	Land Rights - Clearing	181	2.7%	10,879	289	-	470
20	362	Station Equipment	74,399	2.2%	199,197	4,402	(446)	78,355
21	364	Poles Towers & Fixtures	44,000	2.1%	145,829	3,106	(2,450)	44,657
22	365	Conductors and Devices	68,100	2.6%	232,319	5,971	(1,405)	72,666
23	368	Line Transformers	21,593	3.4%	105,958	3,613	(1,654)	23,552
24	369	Services	6,328	0.2%	10,786	17	-	6,345
25	370	Meters	5,509	6.7%	14,299	955	(300)	6,165
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	3,692	23.0%	11,438	2,628	(47)	6,273
28			219,523	2.9%	735,247	20,981	(6,302)	234,203
29		General Plant						
30	389	Land	897	0.0%	12,093	-	-	897
31	390	Structures - Frame & Iron	269	0.7%	337	2	-	271
32	390.1	Structures - Masonry	5,070	6.1%	25,510	1,559	(31)	6,598
33	391	Office Furniture & Equipment	4,668	3.6%	5,912	215	(1)	4,882
34	391.1	Computer Equipment	47,990	7.6%	69,737	5,307	(165)	53,132
35	392	Transportation Equipment	767	10.7%	20,554	2,201	(751)	2,216
36	394	Tools and Work Equipment	8,188	4.0%	12,920	521	(77)	8,632
37	397	Communication Structures and Equipment	8,623	8.1%	26,780	2,156	(2)	10,777
38			76,473	6.9%	173,842	11,961	(1,028)	87,406
39								
40	108	Total Accumulated Depreciation	345,400	3.2%	1,528,276	49,109	(17,628)	376,881
41								
42		Deduct - Portion of CIAC Depreciated				(3,379)		
43								
44	403	Depreciation Expense				45,730		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	5,210		11,912	186		5,396
48	390	Leasehold Improvements	3,097		5,060	704		3,801
49		Rate Stabilization Adjustment	(1,243)			311		(932)
50		Total Accumulated Amortization	7,064			1,201		8,265
51								
52		Accumulated Amortization per						
53		Balance Sheet	352,464			46,931		385,146

Note: Minor differences due to rounding

TABLE 1 – C – ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (2013)

Line	Account		Acc. Prov. For Depreciation Dec. 31, 2012	Deprec. Rate	Asset Balance Dec. 31, 2012	Depreciation Expense Dec. 31, 2013	Charges less Recoveries	Acc. Prov. For Depreciation Dec. 31, 2013
						($000s)		
		Hydraulic Production Plant						
1	330	Land Rights	(508)	3.8%	962	37	-	(471)
2	331	Structures and Improvements	5,625	1.3%	14,041	181	(65)	5,741
3	332	Reservoirs, Dams and Waterways	6,395	2.0%	31,359	630	(55)	6,970
4	333	Water Wheels, Turbines & Generators	3,937	2.0%	86,302	1,683	(265)	5,355
5	334	Accessory Electrical Equipment	8,322	2.4%	39,856	941	(406)	8,857
6	335	Other Power Plant Equipment	10,991	2.3%	60,984	1,415	(49)	12,357
7	336	Roads, Railroads, and Bridges	523	1.5%	1,287	19	-	542
8			35,284	2.1%	234,790	4,906	(840)	39,350
9		Transmission Plant	-					-
10	350	Land Rights - R/W	(62)	0.0%	7,647	-	-	(62)
11	350.1	Land Rights - Clearing	2,256	1.5%	6,612	97	-	2,353
12	353	Station Equipment	10,795	3.4%	240,061	8,258	(1,277)	17,775
13	355	Poles Towers & Fixtures	5,402	2.6%	91,742	2,422	(4,153)	3,672
14	356	Conductors and Devices	1,446	2.1%	76,099	1,560	(4,049)	(1,043)
15	359	Roads and Trails	152	2.7%	1,121	30	-	182
16			19,989	2.9%	423,283	12,367	(9,479)	22,876
17		Distribution Plant						
18	360	Land Rights - R/W	(868)	0.0%	3,605	-	-	(868)
19	360.1	Land Rights - Clearing	470	2.7%	10,879	289	-	759
20	362	Station Equipment	78,355	2.2%	198,751	4,392	(446)	82,302
21	364	Poles Towers & Fixtures	44,657	2.1%	170,468	3,631	(1,515)	46,772
22	365	Conductors and Devices	72,666	2.6%	239,298	6,150	(1,101)	77,715
23	368	Line Transformers	23,552	3.4%	107,865	3,678	(1,536)	25,695
24	369	Services	6,345	0.2%	10,786	17	(0)	6,362
25	370	Meters	6,165	6.7%	15,186	1,014	(260)	6,918
26	371	Installation on Customers' Premises	(3,413)	0.0%	938	-	-	(3,413)
27	373	Street Lighting and Signal Systems	6,273	23.0%	11,390	2,617	(47)	8,843
28			234,203	2.8%	769,166	21,788	(4,906)	251,085
29		General Plant						
30	389	Land	897	0.0%	13,126	-	-	897
31	390	Structures - Frame & Iron	271	0.7%	337	2	-	273
32	390.1	Structures - Masonry	6,598	6.1%	28,754	1,757	(51)	8,304
33	391	Office Furniture & Equipment	4,882	3.6%	6,033	220	(0)	5,102
34	391.1	Computer Equipment	53,132	7.6%	75,576	5,751	(142)	58,741
35	392	Transportation Equipment	2,216	10.7%	22,246	2,382	(734)	3,864
36	394	Tools and Work Equipment	8,632	4.0%	13,782	555	(70)	9,116
37	397	Communication Structures and Equipment	10,777	8.1%	27,020	2,175	(49)	12,904
38			87,406	6.9%	186,874	12,842	(1,046)	99,202
39								
40	108	Total Accumulated Depreciation	376,881	3.2%	1,614,113	51,903	(16,271)	412,514
41								
42		Deduct - Portion of CIAC Depreciated				(3,637)		
43								
44	403	Depreciation Expense				48,266		
45								
46		Other						
47	114	Utility Plant Acquisition Adjustment	5,396		11,912	186		5,582
48	390	Leasehold Improvements	3,801		5,214	107		3,908
49		Rate Stabilization Adjustment	(932)			311		(621)
50		Total Accumulated Amortization	8,265			604		8,869
51								
52		Accumulated Amortization per						
53		Balance Sheet	385,146			48,870		421,382

Note: Minor differences due to rounding

TABLE 1 – D – CONTRIBUTION IN AID OF CONSTRUCTION (CIAC)

	Actuals		Forecast		Forecast		Forecast	
	2010 Additions	Dec. 31 2010	2011 Additions	Dec. 31 2011	2012 Additions	Dec. 31 2012	2013 Additions	Dec. 31 2013
	($000s)							
1 Gross Book Value	7,368	136,400	7,378	143,777	10,971	154,748	10,694	165,442
2 Accumulated Depreciation	(3,871)	(42,636)	(4,092)	(46,728)	(3,379)	(50,107)	(3,637)	(53,744)
3 Net Book Value		93,763		97,049		104,641		111,698

Note: Minor differences due to rounding

TABLE 1 – E – ALLOWANCE FOR WORKING CAPITAL (2011)

Line	Lag Days Calculation	Lag (Lead) Days	2011 Forecast ($000s)	2011 Extended ($000s)	Weighted Average Lag Days
1	**Revenue**				
2	Tariff Revenue	51.6	281,141	14,507	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	26.6	3,208	85	
5	Contract Revenue	44.3	1,808	80	
6	Miscellaneous Revenue	31.8	2,224	71	
7	Investment Income	15.0	162	2	
8			**288,543**	**14,745**	**51.1**
9					
10	**Expenses**				
11	Power Purchases	42.2	75,956	3,205	
12	Wheeling	40.2	4,243	171	
13	Water Fees	(1.0)	8,977	(9)	
14	*Operating Labour:*				
15	Salaries & Wages	5.3	15,515	82	
16	Employee Benefits	13.2	10,155	134	
17	Contracted Manpower	50.6	8,021	406	
18	Property Tax	2.6	13,917	36	
19	Rental of T&D Facilities	47.8	3,033	145	
20	Office Lease - Kelowna	(15.2)	827	(13)	
21	Office Lease - Trail	91.3	1,212	111	
22	Materials	45.6	2,953	135	
23	Insurance	(182.5)	1,393	(254)	
24	Income Tax	15.2	9,440	143	
25	Interest	82.9	39,364	3,263	
26			**195,004**	**7,555**	**38.7**
27					
28	**Net Lag/(Lead) Days**				**12.4**
29					
30					
31	**Forecast Working Capital Allowance**				($000s)
32					
33	**Lead-Lag Study Allowance**				
34	Net Lag Days/365 times Expenses				6,604
35					
36	**Add Funds Unavailable:**				
37	Customer Loans (related to energy management)			2,773	
38	Employee Loans			340	
39	Uncollectable Accounts			980	
40	Inventory (forecast monthly average investment)			697	
41					4,790
42	**Less Funds Available:**				
43	Average Customer Deposits			3,844	
44	Average HST			189	
45					4,033
46					
47	**2011 FORECAST ALLOWANCE FOR WORKING CAPITAL**				**7,361**

Note: Minor differences due to rounding

TABLE 1 – E – ALLOWANCE FOR WORKING CAPITAL (2012)

	Lag Days Calculation	Lag (Lead) Days	2012 Forecast ($000s)	2012 Extended ($000s)	Weighted Average Lag Days
1	**Revenue**				
2	Tariff Revenue	44.5	294,484	13,105	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	27.6	3,384	93	
5	Contract Revenue	41.4	1,714	71	
6	Miscellaneous Revenue	43.5	2,255	98	
7	Investment Income	15.2	128	2	
8			**301,965**	**13,369**	**44.3**
9					
10	**Expenses**				
11	Power Purchases	42.0	90,984	3,821	
12	Wheeling	40.2	4,725	190	
13	Water Fees	(1.0)	9,681	(10)	
14	*Operating Labour:*			0	
15	Salaries & Wages	6.8	15,705	107	
16	Employee Benefits	36.1	9,999	361	
17	Contracted Manpower	50.6	8,262	418	
18	Property Tax	1.4	14,532	20	
19	Rental of T&D Facilities	48.6	3,206	156	
20	Office Lease - Kelowna	(15.2)	827	(13)	
21	Office Lease - Trail	91.5	1,212	111	
22	Materials	39.4	2,686	106	
23	Insurance	(182.5)	1,441	(263)	
24	Income Tax	15.2	6,052	92	
25	Interest	88.3	41,319	3,648	
26			**210,630**	**8,745**	**41.5**
27					
28	**Net Lag/(Lead) Days**				**2.8**
29					
30					
31	**Forecast Working Capital Allowance**				($000s)
32					
33	**Lead-Lag Study Allowance**				1,589
34	Net Lag Days/365 times Expenses				
35					
36	**Add Funds Unavailable:**				
37	Customer Loans (related to energy management)			2,015	
38	Employee Loans			340	
39	Uncollectable Accounts			930	
40	Inventory (forecast monthly average investment)			697	
41					3,982
42	**Less Funds Available:**				
43	Average Customer Deposits			3,725	
44	Average HST			192	
45					3,917
46					
47	**2012 FORECAST ALLOWANCE FOR WORKING CAPITAL**				**1,654**

Note: Minor differences due to rounding

TABLE 1 – E – ALLOWANCE FOR WORKING CAPITAL (2013)

	Lag Days Calculation	Lag (Lead) Days	2013 Forecast ($000s)	2013 Extended ($000s)	Weighted Average Lag Days
1	**Revenue**				
2	Tariff Revenue	44.5	319,109	14,200	
3	*Other Revenue:*				
4	Apparatus and Facilities Rental	27.6	3,478	96	
5	Contract Revenue	41.4	1,315	54	
6	Miscellaneous Revenue	43.5	2,274	99	
7	Investment Income	15.2	98	1	
8			**326,273**	**14,451**	**44.3**
9					
10	**Expenses**				
11	Power Purchases	42.0	98,821	4,150	
12	Wheeling	40.2	5,233	210	
13	Water Fees	(1.0)	9,853	(10)	
14	*Operating Labour:*			0	
15	Salaries & Wages	6.8	16,210	110	
16	Employee Benefits	36.1	10,032	362	
17	Contracted Manpower	50.6	8,509	431	
18	Property Tax	1.4	15,085	21	
19	Rental of T&D Facilities	48.6	3,238	157	
20	Office Lease - Kelowna	(15.2)	823	(13)	
21	Office Lease - Trail	91.5	909	83	
22	Materials	39.4	3,465	137	
23	Insurance	(182.5)	1,449	(264)	
24	Income Tax	15.2	7,862	120	
25	Interest	88.3	43,553	3,846	
26			**225,043**	**9,340**	**41.5**
27					
28	**Net Lag/(Lead) Days**				**2.8**
29					
30					
31	**Forecast Working Capital Allowance**				($000s)
32					
33	**Lead-Lag Study Allowance**				
34	Net Lag Days/365 times Expenses				1,718
35					
36	**Add Funds Unavailable:**				
37	Customer Loans (related to energy management)			1,308	
38	Employee Loans			340	
39	Uncollectable Accounts			937	
40	Inventory (forecast monthly average investment)			697	
41					3,282
42	**Less Funds Available:**				
43	Average Customer Deposits			3,799	
44	Average Provincial Services Tax			194	
45					3,993
46					
47	**2013 FORECAST ALLOWANCE FOR WORKING CAPITAL**				**1,007**

Note: Minor differences due to rounding

TABLE 1 – F – ADJUSTMENT FOR CAPITAL EXPENDITURES (2011)

		Plant in Service	Months in Rate Base	Weighted Value
		($000s)		($000s)
1	January	1,061	11.5	1,017
2	February	2,605	10.5	2,279
3	March	41,220	9.5	32,632
4	April	11,626	8.5	8,235
5	May	3,419	7.5	2,137
6	June	4,867	6.5	2,636
7	July	2,970	5.5	1,361
8	August	3,180	4.5	1,192
9	September	4,377	3.5	1,277
10	October	4,481	2.5	934
11	November	38,706	1.5	4,838
12	December	16,087	0.5	670
13	**Total**	**134,598**		**59,209**
14	**Less Simple Average**			67,299
15	**Adjustment to Rate Base**			**(8,090)**
16	* Plant in Service are reduced by Contributions in Aid of Construction			

Note: Minor differences due to rounding

TABLE 1 – F – ADJUSTMENT FOR CAPITAL EXPENDITURES (2012)

		Plant in Service	Months in Rate Base	Weighted Value
		($000s)		($000s)
1	January	4,115	11.5	3,943
2	February	4,115	10.5	3,600
3	March	4,115	9.5	3,257
4	April	9,442	8.5	6,688
5	May	9,442	7.5	5,901
6	June	9,442	6.5	5,114
7	July	7,583	5.5	3,476
8	August	7,583	4.5	2,844
9	September	7,583	3.5	2,212
10	October	7,952	2.5	1,657
11	November	7,952	1.5	994
12	December	7,952	0.5	331
13	**Total**	**87,275**		**40,017**
14	**Less Simple Average**			43,638
15	**Adjustment to Rate Base**			**(3,620)**
16	* Plant in Service are reduced by Contributions in Aid of Construction			

Note: Minor differences due to rounding

TABLE 1 – F – ADJUSTMENT FOR CAPITAL EXPENDITURES (2013)

		Plant in Service	Months in Rate Base	Weighted Value
		($000s)		($000s)
1	January	6,011	11.5	5,760
2	February	6,011	10.5	5,259
3	March	6,011	9.5	4,758
4	April	13,793	8.5	9,770
5	May	13,793	7.5	8,621
6	June	13,793	6.5	7,471
7	July	11,078	5.5	5,077
8	August	11,078	4.5	4,154
9	September	11,078	3.5	3,231
10	October	11,617	2.5	2,420
11	November	11,617	1.5	1,452
12	December	11,617	0.5	484
13	**Total**	**127,494**		**58,459**
14	**Less Simple Average**			63,747
15	**Adjustment to Rate Base**			**(5,288)**
16	* Plant in Service are reduced by Contributions in Aid of Construction			

Note: Minor differences due to rounding

SCHEDULE 2 – EARNED RETURN

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	SALES VOLUME (GWh)	3,046	3,187	3,193	3,233
2					
3			($000s)		
4	ELECTRICITY SALES REVENUE	246,791	281,141	294,484	319,109
5					
6	EXPENSES				
7	Power Purchases	71,964	75,956	90,984	98,821
8	Water Fees	9,256	8,977	9,681	9,853
9	Wheeling	4,050	4,243	4,725	5,233
10	Net O&M Expense	36,619	43,108	43,338	44,635
11	Property Tax	12,238	13,917	14,532	15,085
12	Depreciation and Amortization	41,771	45,350	51,399	53,228
13	Other Income	(6,453)	(7,402)	(7,481)	(7,165)
14	Incentive Adjustments	(629)	2,266	(5,416)	-
15	UTILITY INCOME BEFORE TAX	77,975	94,726	92,723	99,418
16	Less:				
17	INCOME TAXES	4,544	9,440	6,052	7,862
18					
19	EARNED RETURN	73,431	85,286	86,671	91,556
20	RETURN ON RATE BASE				
21	Utility Rate Base	945,637	1,071,197	1,145,253	1,212,181
22	Return on Rate Base	7.77%	7.96%	7.57%	7.55%

Note: Minor differences due to rounding

TABLE 2 – A – 1 – SALES BY CUSTOMER CLASS

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		(GWh)			
1	Residential	1,224	1,301	1,264	1,276
2	Commercial Service	654	672	696	709
3	Industrial	234	246	250	255
4	Wholesale	881	909	926	935
5	Lighting	13	13	14	14
6	Irrigation	40	44	44	43
7	Total Sales	3,046	3,187	3,193	3,233
8	Losses and Company Use	280	315	309	310
9	Gross Load	3,326	3,502	3,502	3,543

TABLE 2 – A – 2 – SALES REVENUE BY CUSTOMER CLASS

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
10	Residential	114,375	133,108	137,502	142,235
11	Commercial Service	59,957	64,425	60,245	57,510
12	Industrial	16,093	17,968	18,090	18,419
13	Wholesale	51,765	59,936	62,114	63,864
14	Lighting and Irrigation	4,602	5,704	5,338	5,239
15	Total	246,791	281,141	283,289	287,266

Note: Forecast at 2011 Approved rates

TABLE 2 – A – 3 – CUSTOMER COUNT AT YEAR END

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
16	Residential	97,883	99,457	101,320	103,279
17	Commercial Service	11,419	11,572	11,837	12,130
18	Wholesale	7	7	7	7
19	Industrial	36	36	36	36
20	Lighting & Irrigation	2,905	2,905	2,905	2,905
21	Total	112,250	113,977	116,105	118,357

Note: Minor differences due to rounding

TABLE 2 – B – POWER PURCHASE EXPENSE

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
			GWh		
1	FortisBC	1,530	1,604	1,600	1,604
2	DSM	-	15	53	89
3	Power Purchases (net of surplus sales)	1,796	1,898	1,902	1,939
4	Total System Load (before DSM savings)	3,326	3,517	3,555	3,632
5	Less DSM	-	(15)	(53)	(89)
6	Total System Load (including DSM savings)	3,326	3,502	3,502	3,543
			($000s)		
7	Expense - Energy	60,591	61,466	73,657	79,381
8	Expense - Capacity	12,386	14,330	17,307	18,879
9	Other Adjustments	(1,013)	160	20	561
10	Total Power Purchase Expense	71,964	75,956	90,984	98,821

TABLE 2 – C – WATER FEES

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	Plant Entitlement Use (GWh) in previous year	1,585	1,527	1,604	1,600
2	Water Fees ($000s)	9,256	8,977	9,681	9,853

TABLE 2 – D – WHEELING EXPENSE

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
1	**Wheeling Nomination**		(MW)		
2	Okanagan	2,160	2,220	2,475	2,715
3	Creston	420	420	420	420
4	**Expense**		($000s)		
5	Vernon/Okanagan	3,550	3,723	4,233	4,732
6	Creston	450	459	468	477
7	Other	50	61	24	24
8	Total Wheeling Expense	4,050	4,243	4,725	5,233

Note: Minor differences due to rounding

TABLE 2 – E – OPERATING AND MAINTENANCE EXPENSE

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Total Operating and Maintenance Expense	46,148	53,885	54,172	55,794
2	Capitalized Overhead	(9,529)	(10,777)	(10,834)	(11,159)
3	Net Operating and Maintenance Expense	36,619	43,108	43,338	44,635

TABLE 2 – F – PROPERTY TAX

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Generating Plant	2,830	2,925	2,994	3,066
2	Transmission and Distribution	5,590	6,375	6,707	6,994
3	Substation Equipment	3,273	4,067	4,265	4,435
4	Land and Buildings	545	550	566	590
5	Total Property Tax	12,238	13,917	14,532	15,085

Note: Minor differences due to rounding

TABLE 2 – G – OTHER INCOME

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Apparatus and Facilities Rental				
2	Electric Apparatus Rental	3,864	3,070	3,276	3,374
3	Lease Revenue	141	138	108	104
4		4,005	3,208	3,384	3,478
5	Contract Revenue				
6	Waneta Management Fee	380	457	455	464
7	Waneta Management Fee Capital	8	91	77	-
8	Waneta Carrying Costs	94	94	94	94
9					
10	Brilliant Management Fee	208	320	305	273
11	Brilliant Management Fee Capital	280	221	295	205
12					
13	Fortis Pacific Holdings Inc.	592	625	488	279
14		1,562	1,808	1,714	1,315
15	Miscellaneous Revenue				
16	Connection Charges	489	1,038	1,079	1,122
17	NSF Cheque Charges	11	11	11	12
18	Sundry Revenue	162	66	67	69
19		662	1,115	1,157	1,203
20	Transmission Access Revenue	-	1,109	1,098	1,071
21	Investment Income	224	162	128	98
22					
23	Total	6,453	7,402	7,481	7,165

Note: Minor differences due to rounding

TABLE 2 – H – 1 – 2011 FLOW THROUGH ADJUSTMENTS

		Approved	Forecast	Variance	Income Tax Shield	After Tax Amount	Customer Share	Flow Through Adjustment
					($000s)			
1	2010 Incentive True Up	1,681	2,061	(380)	-	(380)	100%	(380)
2	Interest Expense	40,505	39,364	(1,142)	303	(839)	100%	(839)
3	Transmission Pole Rental Revenue	-	-	(80)	21	(59)	100%	(59)
4	Fibre Leasing Revenue	-	-	(237)	63	(175)	100%	(175)
5	Water Fees Rate Reduction	-	-	(303)	80	(223)	100%	(223)
6	Celgar Tariff Difference	-	-	(1,510)	400	(1,110)	100%	(1,110)
7	Flow Through Adjustment							(2,406)

TABLE 2 – H – 2 – 2011 ROE INCENTIVE ADJUSTMENT

		Approved	Forecast	Variance	Customer Share	ROE Incentive Adjustment
				($000s)		
1	Net Income for ROE Incentive	43,292	48,553	(5,261)	50%	(2,630)
2	Common Equity	437,296	428,479			
3	Allowed ROE	9.90%	11.33%	1.43%	50%	0.72%

Note: Minor differences due to rounding

SCHEDULE 3 – INCOME TAX EXPENSE

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
			($000s)		
1	UTILITY INCOME BEFORE TAX	77,975	94,726	92,723	99,418
2	Deduct:				
3	Interest on Non Rate Base Deferral Account				
3	Interest Expense	35,138	39,364	41,319	43,553
4					
5	ACCOUNTING INCOME	42,837	55,362	51,404	55,865
6					
7	Deductions				
8	Capital Cost Allowance	52,849	56,954	61,305	65,958
9	Capitalized Overhead	9,529	10,777	10,834	11,159
10	Incentive & Revenue Deferrals	629	(2,266)	5,416	-
11	Financing Fees	597	594	345	662
12	All Other (net effect)	3,020	(36)	1,088	574
13		66,624	66,023	78,988	78,353
14					
15	Additions				
16	Amortization of Deferred Charges	3,695	3,233	4,468	4,358
17	Depreciation	38,075	42,118	46,931	48,870
18		41,771	45,350	51,399	53,228
19					
20	TAXABLE INCOME	17,984	34,689	23,814	30,740
21					
22	Tax Rate	28.5%	26.5%	25.0%	25.0%
23					
24	Taxes Payable	5,125	9,193	5,953	7,685
25	Prior Years' Overprovisions/(Underprovisions)	(738)	60	-	-
26	Investment Tax Credit	(27)	-	-	-
27	Deferred Charges Tax Effect	184	186	98	177
28					
29	REGULATORY TAX PROVISION	4,544	9,440	6,052	7,862

Note: Minor differences due to rounding

TABLE 3 – A – CALCULATION OF CAPITAL COST ALLOWANCE (2012)

Line	Class	2011 Closing UCC	2012 Additions	Half-Year Rule	CCA Rate	2012 CCA	Closing UCC
				($000s)			
1	1A	245,339	-	-	4%	9,814	235,525
2	1B	2,987	4,431	2,216	6%	312	7,106
3	17	123,295	9,154	4,577	8%	10,230	122,219
4	2	22,523	-	-	6%	1,351	21,172
5	3	1,331	-	-	5%	67	1,264
6	6	9	-	-	10%	1	8
7	8	5,442	1,052	526	20%	1,194	5,300
8	10	6,719	2,421	1,211	30%	2,379	6,761
9	12	1,026	1,767	884	100%	1,910	883
10	13	1,438	-	-	est	150	1,288
11	42	4,170	518	259	12%	532	4,156
12	45	335	-	-	45%	151	184
13	46	1,803	1,111	556	30%	708	2,206
14	47	357,712	54,761	27,381	8%	30,807	381,666
15	50	1,691	2,794	1,397	55%	1,699	2,786
16		775,820	78,010	39,005		61,305	792,524
17							
18							
19	Land		1,433				
20	Net Salvage		(4,081)				
21	AFUDC		1,079				
22	Capitalized overhead		10,834				
23	CIAC		10,971				
24	Plant in service		98,246				

Note: Minor differences due to rounding

TABLE 3 – A – CALCULATION OF CAPITAL COST ALLOWANCE (2013)

Line	Class	2012 Closing UCC	2013 Additions	Half-Year Rule	CCA Rate	2013 CCA	Closing UCC
					($000s)		
1	1A	235,525	-	-	4%	9,421	226,104
2	1B	7,106	26,569	13,284	6%	1,223	32,451
3	17	122,219	2,766	1,383	8%	9,888	115,097
4	2	21,172	-	-	6%	1,270	19,902
5	3	1,264	-	-	5%	63	1,201
6	6	8	-	-	10%	1	7
7	8	5,300	985	493	20%	1,158	5,127
8	10	6,761	2,436	1,218	30%	2,394	6,803
9	12	883	2,039	1,020	100%	1,903	1,020
10	13	1,288	-	-	est	150	1,138
11	42	4,156	583	292	12%	534	4,205
12	46	2,206	10,199	5,099	30%	2,192	10,213
13	45	184	-	-	45%	83	101
14	47	381,666	64,149	32,075	8%	33,099	412,716
15	50	2,786	3,805	1,902	55%	2,579	4,012
16		792,524	113,531	56,766		65,958	840,097
17							
18							
19	Land		2,900				
20	Net Salvage		(3,000)				
21	AFUDC		2,904				
22	Capitalized overhead		11,159				
23	CIAC		10,694				
24	Plant in service		138,188				

Note: Minor differences due to rounding

SCHEDULE 4 – COMMON SHARE EQUITY

			Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
			($000s)			
1	Share Capital		170,122	180,122	190,122	190,122
2	Retained Earnings		215,131	238,424	268,347	294,199
3						
4	COMMON EQUITY - OPENING BALANCE		385,254	418,546	458,469	484,321
5						
6	Less:	Common Dividends	(15,000)	(16,000)	(19,500)	(20,500)
7						
8	Add:	Net Income	38,293	45,922	45,352	48,002
9		Share Adjustment	-	-	-	-
9		Shares Issued	10,000	10,000	-	-
10						
11	COMMON EQUITY - CLOSING BALANCE		418,546	458,469	484,321	511,823
12						
13	SIMPLE AVERAGE		401,900	438,508	471,395	498,072
14						
15	Adjustment for Shares Issued		(4,973)	(4,918)	-	-
16	Deemed Equity Adjustment		-	(5,111)	(13,294)	(13,200)
17						
18	COMMON EQUITY - AVERAGE		396,927	428,479	458,101	484,872

TABLE 4 – A – CALCULATION OF ADJUSTMENT FOR SHARES ISSUED

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
19	Opening Balance	170,122	180,122	190,122	190,122
20	Adjustment to Opening Balance				
21	Shares Issued #1	10,000	-	-	-
22	Issue Date	Dec 30			
23					
24	Shares Issued #2	-	10,000	-	-
25	Issue Date		Dec 28		
26					
27	Opening Balance x Days in Effect /365	170,122	180,122	190,122	190,122
28	Share Adjustment				
29	Issue #1 times Days in Effect / 365	27	-	-	-
30	Issue #2 times Days in Effect / 365	-	82	-	-
31		170,149	180,204	190,122	190,122
32	less: Simple Average	(175,122)	(185,122)	(190,122)	(190,122)
33	Adjustment for Shares Issued	(4,973)	(4,918)	-	-

Note: Minor differences due to rounding

SCHEDULE 5 – RETURN ON CAPITAL

		Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
		($000s)			
1	Secured and Senior Unsecured Debt	552,603	640,000	637,483	650,151
2	Proportion	58.42%	59.75%	55.66%	53.63%
3	Embedded Cost	6.18%	6.04%	6.03%	5.95%
4	Cost Component	3.61%	3.61%	3.35%	3.19%
5	Return	34,174	38,665	38,422	38,701
6					
7	Short Term Debt	(3,686)	2,718	49,669	77,158
8	Proportion	-0.39%	0.25%	4.34%	6.37%
9	Embedded Cost	-26.15%	25.72%	5.83%	6.29%
10	Cost Component	0.10%	0.07%	0.25%	0.40%
11	Return (including fees)	964	699	2,898	4,852
12					
13					
14	Common Equity	396,927	428,479	458,101	484,872
15	Proportion	41.97%	40.00%	40.00%	40.00%
16	Embedded Cost	9.65%	10.72%	9.90%	9.90%
17	Cost Component	4.05%	4.29%	3.96%	3.96%
18	Return	38,293	45,922	45,352	48,002
19					
20	TOTAL CAPITALIZATION	945,844	1,071,197	1,145,253	1,212,181
21	RATE BASE	945,637	1,071,197	1,145,253	1,212,181
22					
23	Earned Return	73,430	85,286	86,671	91,556
24					
25	RETURN ON CAPITAL	7.76%	7.96%	7.57%	7.55%
26	RETURN ON RATE BASE	7.77%	7.96%	7.57%	7.55%

Note: Minor differences due to rounding

Appendix 7A

ANALYSIS OF TAX IMPACT OF INCENTIVE ADJUSTMENT

INCENTIVE SHARING ANALYSIS

TABLE 7A – 1 SUMMARY OF AMOUNTS REFUNDED TO CUSTOMERS IN 2012

	($000s)
1 Customer Incentive Sharing (Presented After Tax)	5,416
2 Reduction in Income Tax Expense	1,840
3 Reduction in Financing Costs	170
4 Total Reduction in 2012 Customer Revenue	**7,426**

Note: Minor differences due to rounding

TABLE 7A – 2 REVENUE REQUIREMENTS OVERVIEW

		No Customer Incentive A Forecast 2012	Customer Incentive B-A Forecast 2012 ($000s)	With Customer Incentive B Forecast 2012
1	Sales Volume (GWh)	3,193	-	3,193
2	Rate Base	1,147,913	(2,660)	1,145,253
3	Return on Rate Base	7.57%	0.00%	7.57%
4				
5	**REVENUE DEFICIENCY**			
6				
7	**POWER SUPPLY**			
8	Power Purchases	90,984	-	90,984
9	Water Fees	9,681	-	9,681
10		100,665	-	100,665
11	**OPERATING**			
12	O&M Expense	54,172	-	54,172
13	Capitalized Overhead	(10,834)	-	(10,834)
14	Wheeling	4,725	-	4,725
15	Other Income	(7,481)	-	(7,481)
16		40,582	-	40,582
17	**TAXES**			
18	Property Taxes	14,532	-	14,532
19	Income Taxes	7,892	(1,840)	6,052
20		22,424	(1,840)	20,584
21	**FINANCING**			
22	Cost of Debt	41,384	(64)	41,319
23	Cost of Equity	45,457	(105)	45,352
24	Depreciation and Amortization	51,399	-	51,399
25		138,240	(170)	138,070
26				
27	Prior Year Incentive True Up	-	(380)	(380)
28	Flow Through Adjustments	-	(2,406)	(2,406)
29	ROE Sharing Incentives	-	(2,630)	(2,630)
30		-	(5,416)	(5,416)
31				
32	**TOTAL REVENUE REQUIREMENT**	301,910	(7,426)	294,484
33				
34	ADJUSTED REVENUE REQUIREMENT	301,910	(7,426)	294,484
35	**LESS: REVENUE AT APPROVED RATES**	283,289	-	283,289
36	**REVENUE DEFICIENCY for Rate Setting**	18,621	(7,426)	11,195
37				
38	**RATE INCREASE**	**6.60%**	**-2.60%**	**4.00%**

Note: Minor differences due to rounding

TABLE 7A – 3 INCOME TAX EXPENSE (SCHEDULE 3)

		No Customer Incentive A Forecast 2012	Customer Incentive B-A Forecast 2012	With Customer Incentive B Forecast 2012
			($000s)	
1	UTILITY INCOME BEFORE TAX	94,733	(2,010)	92,723
2	Deduct:			
3	Interest on Non Rate Base Deferral Account			
3	Interest Expense	41,384	(64)	41,319
4				
5	ACCOUNTING INCOME	53,349	(1,946)	51,404
6				
7	Deductions			
8	Capital Cost Allowance	61,305	-	61,305
9	Capitalized Overhead	10,834	-	10,834
10	Incentive & Revenue Deferrals	-	5,416	5,416
11	Financing Fees	345	-	345
12	All Other (net effect)	1,088	-	1,088
13		73,572	5,416	78,988
14				
15	Additions			
16	Amortization of Deferred Charges	4,468	-	4,468
17	Depreciation	46,931	-	46,931
18		51,399	-	51,399
19				
20	TAXABLE INCOME	31,176	(7,362)	23,814
21				
22	Tax Rate	25.0%	25.0%	25.0%
23				
24	Taxes Payable	7,794	(1,840)	5,953
26	Investment Tax Credit			
26	Deferred Charges Tax Effect	98	-	98
27				
28	**REGULATORY TAX PROVISION**	**7,892**	**(1,840)**	**6,052**

Appendix 7B

RECONCILIATION OF CAPITAL EXPENDITURE WITH COST OF REMOVAL 2011-2013

TABLE 7B – 1 CAPITAL EXPENDITURE WITH COST OF REMOVAL (2011)

		Expenditures 2011	Cost of Removal (COR) 2011	Expenditures 2011 with COR
			($000s)	
Hydraulic Production				
1	Upper Bonnington Spill Gate Rebuild	621	-	621
2	Lower Bonnington Power House Windows	354	47	401
3	South Slocan Unit 1 Life Extension	79	-	79
4	Corra Linn Unit 1 Life Extension	3,055	17	3,072
5	Corra Linn Unit 2 Life Extension	12,748	844	13,592
6	All Plants Station Service	1,352	40	1,392
7	Lower & Upper Bonnington Plant Totalizer Upgrade	89	-	89
8	South Slocan Plant Automation	251	-	251
9	South Slocan Fire Panel	274	-	274
10	Lower & Upper Bonnington Communication Network	43	-	43
11	Upper Bonnington Extension Trash Rack Gantry Replacement	166	31	197
12	South Slocan Domestic Water Supply Ph.3	39	-	39
13	Queen's Bay Level Gauge Building Ph.1	21	-	21
14	All Plants Minor Sustainment	634	75	709
15		**19,726**	**1,054**	**20,780**
Transmission Plant				
16	Okanagan Transmission Reinforcement	15,692	1,400	17,092
17	Ellison to Sexsmith Transmission Tie	693	-	693
18	Huth Bus Reconfiguration	4,992	9	5,001
19	Benvoulin Distribution Source	928	29	958
20	Capitalized Inventory	542	-	542
21	Recreation Capacity Increase Stages 1,2,3	(23)	-	(23)
22	30 Line Conversion Slocan & Coffee Creek Substations	337	(40)	297
23	Transmission Line Urgent Repairs	421	70	491
24	Transmission Line Right of Way Easements	358	-	358
25	Transmission Line Condition Assessment	469	-	469
27	Transmission Line Rehabilitation	1,249	355	1,604
26	Castlegar Substation Switch Upgrade	48	-	48
28	Station Assessment / Minor Planned Projects	634	74	708
29	Station Unforseen Repairs	604	70	674
30	Bulk Oil Breaker Replacement	196	10	206
31	Lambert 230kv Switch Replacement	567	-	567
32	OK Mission LTC Upgrade	720	-	720
33	Add Arc Flash Detection to Legacy Metal Clad Switchgear	287	-	287
34	Passmore - 19 Line Breaker	2,113	-	2,113
35	Creston Substation Protection Upgrade	107	51	157
36		**30,933**	**2,029**	**32,962**
Distribution Plant				
37	New Connects System Wide	15,969	167	16,136
38	Distribution Unplanned Growth	986	-	986
39	Distribution Urgent Repairs	2,500	342	2,842
40	Distribution Line Condition Assessment	992	-	992
41	Distribution Line Rehabilitation	1,937	366	2,303
42	Distribution Line Rebuilds	1,886	185	2,071
43	Distribution Line Small Planned Capital	764	41	805
44	Forced Upgrades and Line Moves	1,387	184	1,572
45		**26,422**	**1,285**	**27,707**
General Plant				
46	Distribution Station Automation	2,127	45	2,172
47	Mandatory Reliability Standards Compliance	600	-	600
48	Communications Upgrades	2,138	55	2,193
49	Kootenay Long Term Facility Strategy	503	-	503
50	Okanagan Long Term Solution	507	-	507
51	Information Systems	4,682	-	4,682
52	Vehicles	2,738	-	2,738
53	Metering Changes	472	-	472
54	Telecommunications	368	26	394
55	Buildings	1,288	-	1,288
56	Furniture & Fixtures	182	-	182
57	Tools & Equipment	622	-	622
58	Environmental Compliance (PCB Mitigation)	1,926	200	2,126
59		**18,154**	**326**	**18,479**
60				
61	**GROSS EXPENDITURE**	**95,235**	**4,693**	**99,929**
62				
63	Less Contribution in Aid of Construction (CIAC)	(7,378)	-	(7,378)
64				
65	**NET EXPENDITURE**	**87,858**	**4,693**	**92,551**
66				
67	Demand Side Management (Net of Tax)	5,396	-	5,396
68				
69	**NET EXPENDITURE WITH DSM**	**93,254**	**4,693**	**97,947**

Note: Minor differences due to rounding

TABLE 7B – 2 CAPITAL EXPENDITURE WITH COST OF REMOVAL (2012)

		Expenditures 2012	Cost of Removal (COR) 2012	Expenditures 2012 with COR
			($000s)	
	Hydraulic Production			
1	All Plants Concrete and Structural Rehabilitation	495	75	570
2	Upper Bonnington Spillgate Rebuild	1,061	24	1,085
3	Lower Bonnington Power House Windows	366	-	366
4	Corra Linn Unit 2 Life Extension	3,423	-	3,423
5	All Plants Station Service	672	-	672
6	Lower & Upper Bonnington Plant Totalizer Upgrade	90	-	90
7	Corra Linn Unit 3 Completion	675	47	722
8	Upper Bonnington Old Plant Various Unit Upgrades	1,277	34	1,311
9	Lower & Upper Bonnington & Corra Linn Fire Panels	250	-	250
10	All Plants Safety & Security	471	-	471
11	All Plants Minor Sustainment	1,061	110	1,171
12		**9,841**	**290**	**10,131**
	Transmission Plant			
13	Okanagan Transmission Reinforcement	2,219	-	2,219
14	Ellison to Sexsmith Transmission Tie	6,825	297	7,122
15	Grand Forks Transformer Addition	2,491	-	2,491
16	Transmission Line Condition Assessment	522	-	522
17	Transmission Line Rehabilitation	2,961	411	3,372
18	Transmission Line Urgent Repairs	513	81	594
19	Transmission Right of Way Easements	400	-	400
20	6 Line / 26 Line River Crossing Reconfiguration	925	260	1,185
21	27 Line Rebuild (Corra Linn - Salmo)	1,057	104	1,161
22	21-24 Lines Rebuild (Generation Plants)	2,115	104	2,219
23	Environmental Compliance (PCB Mitigation)	10,749	520	11,269
24	Station Urgent Repairs	711	107	818
25	Station Assessment / Minor Planned Projects	1,322	21	1,343
26	Add Arc Flash Detection to Legacy Metal Clad Switchgear	529	10	539
27	SCADA Systems Sustainment	707	-	707
28	Kelowna 138kV Loop Fibre Intallation	1,212	-	1,212
29	Communications Upgrades	13	-	13
30		**35,271**	**1,915**	**37,186**
	Distribution Plant			
31	New Connects System Wide	21,942	86	22,028
32	Small Growth Projects	1,059	10	1,069
33	Distribution Unplanned Growth Projects	826	98	924
34	Glenmerry Feeder 2 to Glenmerry Feeder 3 Tie Line	593	3	596
35	Distribution Urgent Repairs	2,083	328	2,411
36	Distribution Line Condition Assessment	1,410	-	1,410
37	Distribution Line Rehabilitation	4,646	652	5,298
38	Distribution Line Rebuilds	1,372	307	1,679
39	Distribution Line Small Planned Capital	649	77	726
40	Forced Upgrades and Line Moves	1,800	212	2,012
41	41 Line Salvage & Distribution Underbuild Rehabilitation	793	1,274	2,067
42		**37,173**	**3,047**	**40,220**
	General Plant			
43	Communications Upgrades	397	-	397
44	Kootenay Long Term Facility Strategy	6,020	-	6,020
45	Okanagan Long Term Solution	69	-	69
46	Central Warehousing	1,755	-	1,755
47	Advanced Metering Infrastruture	4,501	-	4,501
48	Information Systems	5,672	-	5,672
49	Vehicles	2,421	120	2,541
50	Metering Changes	403	-	403
51	Telecommunications	121	-	121
52	Buildings	1,362	-	1,362
53	Furniture & Fixtures	121	-	121
54	Tools & Equipment	528	-	528
55		**23,370**	**120**	**23,490**
56				
57	**GROSS EXPENDITURE**	**105,656**	**5,372**	**111,028**
58				
59	Less Contribution in Aid of Construction (CIAC)	(10,971)	-	(10,971)
60				
61	**NET EXPENDITURE**	**94,685**	**5,372**	**100,057**
62				
63	Demand Side Management (Net of Tax)	5,798	-	5,798
64				
65	**NET EXPENDITURE WITH DSM**	**100,483**	**5,372**	**105,855**

Note: Minor differences due to rounding

TABLE 7B – 3 CAPITAL EXPENDITURE WITH COST OF REMOVAL (2013)

		Expenditures 2013	Cost of Removal (COR) 2013	Expenditures 2013 with COR
			($000s)	
	Hydraulic Production			
1	All Plants Concrete and Structural Rehabilitation	543	74	617
2	Lower Bonnington Power House Windows	8	-	8
3	Upper Bonnington, South Slocan & Corra Linn Power House Windows	430	-	430
4	Lower & Upper Bonnington & Corra Linn Fire Panels	259	-	259
5	All Plants Safety & Security	475	-	475
6	All Plants Minor Sustainment	1,051	107	1,158
7		**2,766**	**181**	**2,947**
	Transmission Plant			
8	Ellison to Sexsmith Transmission Tie	413	-	413
9	Grand Forks Transformer Addition	4,714	-	4,714
10	Kelowna Bulk Transformr Capacity Addition	3,720	-	3,720
11	Transmission Line Condition Assessment	485	-	485
12	Transmission Line Rehabilitation	2,298	323	2,621
13	Transmission Line Urgent Repairs	535	85	620
14	Transmission Right of Way Easements	400	-	400
15	19 Line / 29 Line Reconfiguration	367	424	791
16	20 Line Rebuild (Warfield Terminal - Salmo)	4,133	531	4,664
17	Environmental Compliance (PCB Mitigation)	11,022	531	11,553
18	Station Urgent Repairs	787	120	907
19	Station Assessment / Minor Planned Projects	1,333	21	1,354
20	Add Arc Flash Detection to Legacy Metal Clad Switchgear	533	11	544
21	Huth Low Voltage Breaker Replacement	69	-	69
22	SCADA Systems Sustainment	733	-	733
23	Kelowna 138kV Loop Fibre Intallation	2,549	-	2,549
24		**34,091**	**2,045**	**36,136**
	Distribution Plant			
25	New Connects System Wide	21,388	86	21,474
26	Small Growth Projects	852	36	888
27	Distribution Unplanned Growth Projects	831	99	930
28	Ellison Feeder 2 to Sexsmith Feeder 1 Tie	1,102	59	1,161
29	Distribution Urgent Repairs	1,997	318	2,315
30	Distribution Line Condition Assessment	1,398		1,398
31	Distribution Line Rehabilitation	3,142	375	3,517
32	Distribution Line Rebuilds	1,328	332	1,660
33	Distribution Line Small Planned Capital	738	88	826
34	Forced Upgrades and Line Moves	2,156	257	2,413
35		**34,932**	**1,651**	**36,583**
	General Plant			
36	Communications Upgrades	400	-	400
37	Kootenay Long Term Facility Strategy	10,477	-	10,477
38	Trail Office Lease Purchase	10,000	-	10,000
39	Okanagan Long Term Solution	75	-	75
40	Advanced Metering Infrastruture	27,931	-	27,931
41	Information Systems	4,692	-	4,692
42	Vehicles	2,436	138	2,574
43	Metering Changes	406	-	406
44	Telecommunications	183	-	183
45	Buildings	883	-	883
46	Furniture & Fixtures	122	-	122
47	Tools & Equipment	457	-	457
48		**58,062**	**138**	**58,200**
49				
50	**GROSS EXPENDITURE**	**129,851**	**4,015**	**133,866**
51				
52	Contribution in Aid of Construction (CIAC)	(10,694)	-	(10,694)
53				
54	**NET EXPENDITURE**	**119,157**	**4,015**	**123,172**
55				
56	Demand Side Management (Net of Tax)	5,909	-	5,909
57				
58	**NET EXPENDITURE WITH DSM**	**125,066**	**4,015**	**129,081**

Note: Minor differences due to rounding

2012 – 2013 Revenue Requirements
(2012-13 RRA)

Tab 8
Approvals Sought and Proposed Regulatory Process

June 30, 2011

FortisBC Inc.

Table of Contents

8.0 APPROVALS SOUGHT

This Application is comprised of two parts (collectively referred to as the Application). Each part is, in turn, comprised of different components:

Part I – 2012 – 2013 Revenue Requirements

a) 2012 – 2013 Revenue Requirements

b) 2012 – 2013 Capital Expenditure Plan

Part II – 2012 Integrated System Plan

a) 2012 Long Term Capital Expenditure Plan

b) 2012 Resource Plan

c) 2012 Long Term Demand Side Management Plan

FortisBC respectfully seeks an Order or Orders of the British Columbia Utilities Commission (the Commission) under the applicable provisions of the *Utilities Commission Act* (the Act) granting the following approvals or acceptance as set forth below:

2012 – 2013 Revenue Requirements

Interim Approval of 2012 Rate

I a) i Pursuant to section 89 of the Act and section 15 of the *Administrative Tribunals Act*, approval of an interim refundable rate increase of 4.0 percent, effective January 1, 2012, with any difference between interim and permanent rates to be refunded to or collected from customers by way of a general rate adjustment between the effective date of the permanent rates and December 31, 2012. Interim rates may be necessary as a Commission decision on the Application to implement a permanent rate for 2012 is unlikely before January 1, 2012.

2012 and 2013 Rate Approval

Pursuant to sections 59 to 61 of the Act, approval of the following items:

I a) ii the revenue requirements in the amount of $294.484 million in 2012 and $319.108 million in 2013, as set out in section 4.1 of the Application, resulting in a firm rate increase of 4.0 percent, effective January 1, 2012 and a firm rate increase of 6.9 percent effective January 1, 2013.

I a) iii charges between FortisBC and its affiliates regulated by the Commission based on the fully loaded cost, not including overheads charges, as set out in Section 4.3.4.18 of the Application.

I a) iv deferral accounts for variances from forecast of Power Purchase Expense, to be amortized into rates in 2014, and for variances from forecast of Sales Revenue, to be amortized into rates over a three-year period beginning in 2014, as described in Sections 4.1 and 5.4 of the Application.

I a) v the establishment and amortization of Deferral Accounts as set out in Section 5.4 of the Application.

I a) vi Approval of $4.7 million for inclusion in Rate Base for 2011 net Cost of Removal as set out in section 5.3.1.2 of the Application.

Pursuant to section 56 of the Act,

I a) vii Approval of depreciation rates as set out in Section 4.7.2 of the Application.

2012 – 2013 Capital Expenditure Plan

I b) i Pursuant to section 44.2(3) of the Act, approval that the expenditures and projects or programs for which the expenditures are requested are in the public interest.

I b) ii Approval that FortisBC's 2012 – 2013 Capital Expenditure Plan meets the requirements of section 45(6) of the Act.

2012 Integrated System Plan

II Pursuant to section 44.1(6) of the Act, acceptance that FortisBC's 2012 Integrated System Plan, comprised of three components – 2012 Resource Plan, 2012 Long Term Capital Plan, and the 2012 Long Term Demand Management Plan, is in the public interest.

8.1 PROPOSED REGULATORY PROCESS

FortisBC proposes a negotiated settlement process, or in the alternative a written public hearing process for the review of both parts of this Application: the 2012 – 2013 Revenue Requirements Application, including the 2012 - 2013 Capital Expenditure Plan, and the 2012 Integrated System Plan.

In the regulatory proceeding addressing FortisBC's 2009 Revenue Requirement, the Commission approved a negotiated settlement agreement (NSA), in which the Settlement Agreement for the 2007-2009 Performance-Based Regulation Plan was extended through 2011. The NSA further contemplated that the 2012 revenue requirement application be reviewed by oral public hearing. FortisBC has full intention to comply with the NSA's contemplation regarding an oral hearing process for the 2012 - 2013 Revenue Requirements Application, if it remains the preference of the Commission and Registered Interveners. However, the Company believes that the issues raised in the Application can be efficiently and more cost-effectively addressed through a negotiated settlement process, or in the alternative a written public hearing process. FortisBC proposes a regulatory schedule that contains the following processes that offers a thorough regulatory review, yet will improve the regulatory efficiency of the review:

1. The Load and Customer Forecast is exempt from the written Information Request process. Pursuant to the 2011 Negotiated Settlement Agreement, and subject to a Procedural Order of the Commission Panel, the forecast methodology will be examined by a Load Forecast Technical Committee consisting of interested Interveners and members of the Commission Staff as full and active participants, in addition to FortisBC staff. It is FortisBC's intention that the Committee's review of the methodology will be similar in scope to an Information Request process, but will take place in an interactive and cooperative manner. The purpose of the Committee will be to determine whether the Load Forecast is technically sound and if necessary to identify and incorporate improvements. A report outlining the Committee's review process and recommendations would be submitted in evidence prior to the planned Procedural Conference.

   This approach was used successfully in FortisBC's 2005 Revenue Requirements Application. The 2005 committee members reported that they had no serious methodological concerns with the forecast, and the Commission Panel accepted its recommendation that the load forecast not be examined as part of the oral hearing for the 2005 Revenue Requirements. In addition, no written submissions on the 2005 load forecast were received in argument by any of the Interveners.

2. Following the Information Request component, a Procedural Hearing is proposed to determine the remainder of the review process for the Application. The Procedural Hearing will address whether Interveners intend to file evidence in the Application,

whether the Application proceed (in whole or in part) by way of a Negotiated Settlement Process, and timing and related issues for the remainder of the process.

As 2011 is the final year of its Performance-Based Regulation Plan, an Annual Review is required to review the Company's forecast 2011 financial results and non-financial performance and to confirm FortisBC's financial incentive in respect of the 2011 year. The Company proposes that the Annual Review be held adjacent to the Procedural Conference.

FortisBC proposes the following timeline for review of the 2012 - 2013 Revenue Requirements and Capital Expenditure Plan and 2012 Integrated System Plan:

Action	Date (2011)
Registration Deadline for Interveners and Interested Parties	Wednesday, July 20
Workshop	Friday, July 22
Commission and Intervener Information Request No. 1	Wednesday, August 10
FortisBC Response to Information Requests No. 1	Friday, September 9
Commission and Intervener Information Request No.2	Friday, September 30
FortisBC Response to Information Request No. 2	Monday, October 21
2011 Annual Review	Tuesday, October 25
Procedural Conference	Wednesday, October 26
Load Forecast Technical Committee Report filed	Friday, October 28
Procedural Order	Tuesday, November 1
Intervener Evidence (if required)	Wednesday, November 9
Information Request No. 1 to Interveners (if required)	Tuesday, November 22
Intervener Response to Information Request No. 1 (if required)	Tuesday, December 6
FortisBC Rebuttal Evidence (if required)	Tuesday, December 13
Negotiated Settlement Process (if applicable)	Wednesday, January 4
FortisBC Final Submission (if applicable)	Wednesday, January 18
Intervener Final Submission (if applicable)	Wednesday, January 25
FortisBC Reply Submission (if applicable)	Wednesday, February 1
	Date (2012)
Commission Decision (requested)	Friday, March 16
Firm Rates Effective	Tuesday, May 1

Appendix A

GLOSSARY OF ABBREVIATIONS AND STATION ABBREVIATIONS

Abbreviations

2005 SDP 2005-2024 Transmission and Distribution System Development Plan

2009 COSA and RDA 2009 Cost of Service Analysis and Rate Design Application

2012-13 Capital Plan 2012 - 2013 Capital Expenditure Plan

AACE Association for the Advancement of Cost Engineering

AAM Automatic Adjustment Mechanism

AC Alternating Current

Act Utilities Commission Act

ADC Automated Dimming Controls

AFUDC Allowance for Funds Used During Construction

AM/FM Automated Mapping/Facilities Management

AMI Advanced Metering Infrastructure

AOCI Accumulated Other Comprehensive Income

ASC US GAAP Accounting Standards Codification

ASL Average Service Life

AVL Automated Vehicle Locator

B/C Ratio Benefit Cost Ratio

BC Hydro PPA BC Hydro Power Purchase Agreement

BC MRS British Columbia Mandatory Reliability Standards

BCTC British Columbia Transmission Corporation

BCUC British Columbia Utilities Commission

BPPA Brilliant Power Purchase Agreement

BTS Brilliant Terminal Station

CBOC Conference Board of Canada

CBSM Community-Based Social Marketing

CCA Capital Cost Allowance

Abbreviations

CDD Cooling Degree Days

CDPR Conservation Demand Potential Review

CEA Canadian Electricity Association

Celgar Zellstoff Celgar Limited Partnership

CETI Centre for Energy Advancement through Technological Innovations

CEUS Commercial End Use Survey

CGAAP Canadian Generally Accepted Accounting Principles

CIAC Contributions in Aid of Construction

CICA Canadian Institute of Chartered Accountants

CIP Cyber Infrastructure Protection

CMMS Computerized Maintenance Management System

COC Code of Conduct

COPE Canadian Office and Profession Employees Union

COSA Cost of Service Analysis

CPA Canal Plant Agreement

CPAB Canadian Public Accountability Board

CPC Columbia Power Corporation

CPCN Certificate of Public Convenience and Necessity

CPC/CBT Columbia Power Corporation

CPI Consumer Price Index

CRA Canada Revenue Agency

CSA Canadian Standards Association

CSI Customer Satisfaction Index

CWIP Construction Work In Progress

DC Direct Current

Abbreviations

DC&P Disclosure Controls and Procedures

DSM Demand Side Management

EARSL Expected Average Remaining Service Life

EIA US Energy Information Administration

EIT Engineer-in-Training

EMIS Energy Management Information System

Energy Plan 2007 BC Energy Plan

ESB Enterprise Service Bus

ESC Electricity Sector Council

FASB Financial Accounting Standards Board

FEI FortisBC Energy Inc. (formerly Terasen Gas Inc.)

FEU FortisBC Energy Utilities

FTE Full Time Equivalent

GDP Gross Domestic Product

GHG Greenhouse Gas

GIS Geographic Information System

GPS Global Positioning System

GST Goods and Services Tax

GWA General Wheeling Agreement

HDD Heating Degree Days

HLH Heavy Load Hours

HR Human Resources

HRSDC Human Resources and Social Development Canada

HS&E Health, Safety and Environment

HST Harmonized Sales Tax

Abbreviations

IASB International Accounting Standards Board

IBEW International Brotherhood of Electrical Workers Union

ICFR Internal Controls Over Financial Reporting

IFRS International Financial Reporting Standards

IPP Independent Power Producers

IRU Indefeasible Right of Use

IS Information Systems

ISP Integrated System Plan

IT Information Technology

ITC Input Tax Credit

LLH Light Load Hours

Mid-C Mid-Columbia

MOV Metal Oxide Varistor

MRS Mandatory Reliability Standards

MTN Medium Term Note

NERC North American Electric Reliability Corporation

NSA Negotiated Settlement Agreement

NSF Non-sufficient funds

NWPP Northwest Power Pool

O&M Operating and Maintenance

OATT Open Access Transmission Tariff

OPEB Other Post-Employment Benefits

OSC Ontario Securities Commission

OTR Okanagan Transmission Reinforcement

PBR Performance Based Regulation

Abbreviations

PCB Polychlorinated Biphenyls

PLP Princeton Light and Power

PLT Power Line Technician

PP&E Property, Plant and Equipment

PPA Power Purchase Agreement

PPME Power Purchase Management Expense

PRM Planning Reserve Margin

PSH Pumped Storage Hydro

PST Provincial Sales Tax

Rate Base Utility Mid Year Rate Base

RAS Remedial Action Scheme

RDA Rate Design Application

REC Residential Energy Credit

REUS Residential End Use Survey

RIB Residential Inclining Block

RMS Reliability Management System

ROE Return on Equity

RRA Revenue Requirements Application

RRSP Registered Retirement Savings Plan

RS 3808 (BC Hydro) Rate Schedule 3808

RSA Rate Stabilization Adjustment

SAIDI System Average Duration Interruption Index

SAIFI System Average Frequency Interruption Index

SARA Species at Risk Act

SCADA System Control and Data Acquisition

Abbreviations

SCC System Control Centre

SCM Supply Chain Management

SDP System Development Plan

SERP Supplemental Executive Retirement Plan

SIR Self Insurance Reserve

SOX Sarbanes-Oxley Act

T&D Transmission and Distribution

Teck Teck Metals Ltd.

TPP Transfer Pricing Policy

TRC Total Resource Cost

UBC University of British Columbia

UBCO University of British Columbia Okanagan

UCC Undepreciated Capital Cost

ULE Upgrade and Life Extension

UPC Use per Customer

US GAAP US Generally Accepted Accounting Principles

US GAAP Application Fortis BC Utilities Application for approval for the use of US GAAP

VIR Vehicle Incident Rate

WAN Wide Area Network

WAX CAPA Waneta Expansion Capacity Purchase Agreement

WECC Western Electricity Coordinating Council

Station Information

Designation	Station Name	Owner
AAL	Lambert, A. A. Terminal	FBC
ASM	Mawdsley, A.S. Terminal	FBC
AWA	Arawana Substation	FBC
AXR	Apex Repeater	FBC
BAR	Baldy Repeater	FBC
BEN	Bentley Terminal	FBC
BEP	Beaver Park Substation	FBC
BEV	Benvoulin Substation	FBC
BGR	Blue Grouse Repeater	FBC
BLK	Black Mountain Substation	FBC
BLR	Blue Mountain Repeater	FBC
BLU	Blueberry Substation	FBC
BRL	Braeloch Substation	FBC
BWR	Big White Repeater	FBC
BWS	Big White Substation	FBC
CAS	Castlegar Substation	FBC
CHR	Christina Lake Substation	FBC
COF	Coffee Creek Substation	FBC
COR	Corra Linn Generating Station	FBC
COT	Cottonwood Substation	FBC
CRA	Crawford Bay Substation	FBC
CRE	Creston Substation	FBC
CSC	Cascade Substation	FBC
DGB	Bell, D.G. Terminal	FBC
DUC	Duck Lake Substation	FBC
ELL	Ellison Substation	FBC
FRU	Fruitvale Substation	FBC
GFT	Grand Forks Terminal	FBC
GLE	Glenmore Substation	FBC
GLM	Glenmerry Substation	FBC
GRA	Granite Substation	FBC
GRE	Greenwood Substation	FBC
GRS	Greenwood Distribution Stepdown	FBC
HED	Hedley Substation	FBC
HER	Hearns Substation	FBC
HOL	Hollywood Substation	FBC
HUT	Huth Substation	FBC
JOR	Joe Rich Substation	FBC
KAL	Kaleden Substation	FBC
KAS	Kaslo Substation	FBC
KER	Keremeos Substation	FBC
KET	Kettle Valley Substation	FBC
KMR	Kobau Mountain Repeater	FBC
LBO	Lower Bonnington Generating Station	FBC
LEE	Lee, F.A. Terminal	FBC
M12	12 MVA Mobile Substation	FBC
M18	18 MVA Mobile Substation	FBC
M25	25 MVA Mobile Substation	FBC

Station Information

Designation	Station Name	Owner
M32	32 MVA Mobile Substation	FBC
M6.5	6.5 MVA Mobile Substation	FBC
MCM	McKinney Microwave Substation	FBC
MDY	Midway Distribution Stepdown	FBC
MID	Midway Substation	FBC
MMR	Midgeley Mountain Repeater	FBC
MSR	Missezula Repeater	FBC
NAR	Naramata Substation	FBC
NKM	Nk'Mip Substation	FBC
NKW	Mt. Nkwala Repeater	FBC
NWD	North Warfield Substation	FBC
OKF	OK Falls Substation	FBC
OKM	OK Mission Substation	FBC
OLI	Oliver Substation	FBC
OOT	Ootischenia Substation	FBC
OSO	Osoyoos Substation	FBC
PAS	Passmore Substation	FBC
PAT	Paterson Substation	FBC
PIN	Pine Street Substation	FBC
PLA	Playmor Substation	FBC
PMR	Phoenix Mountain Repeater	FBC
PPR	Pilot Point Repeater	FBC
PRI	Princeton Substation	FBC
REC	Recreation Substation	FBC
RGA	Anderson, R.G. Terminal	FBC
RMR	Red Mountain Repeater	FBC
ROC	Rock Creek Substation	FBC
ROS	Rossland Substation	FBC
RSM	Rosemont Switching Station	FBC
RUC	Ruckles Substation	FBC
SAL	Salmo Substation	FBC
SAU	Saucier Substation	FBC
SEX	Sexsmith Substation	FBC
SLC	South Slocan Generating Station	FBC
SLO	Slocan City Substation	FBC
SMR	Santa Rosa Repeater	FBC
SRR	Slocan Ridge Repeater	FBC
STC	Stoney Creek Substation	FBC
SUM	Summerland Substation	FBC
TAR	Tarrys Substation	FBC
TRA	Trail Substation	FBC
TRC	Trout Creek Substation	FBC
TUR	Tulameen Repeater	FBC
UBO	Upper Bonnington Generating Station	FBC
USS	Upper Bonnington Switching Station	FBC
VAL	Valhalla Substation	FBC
VAS	Vaseux Lake Terminal	FBC
WAR	Warfield Substation	FBC

Station Information

Designation	Station Name	Owner
WAT	Waterford Substation	FBC
WEB	West Bench Substation	FBC
WES	Westminster Substation	FBC
WHI	Whitewater Substation	FBC
WTS	Warfield Terminal Station	FBC
WYN	Wynndel Substation	FBC
YMR	Ymir Substation	FBC
YRT	Ymir Repeater	FBC
WAX	Waneta Expansion Generating Station	FTS
WDN	Walden North Generating Station	FTS
KRE	COK - Recreation Substation	COK
KSA	COK - Saucier Substation	COK
KSP	COK - Spall Substation	COK
ALH	Arrow Lakes Hydro Generating Station	CPC
BRD	Brilliant Generating Station	CPC
BRX	Brilliant Expansion Generating Station	CPC
BSS	Brilliant Switching Station	CPC
BTS	Brilliant Terminal Station	CPC
BCG	BC Gas (Terasen) Substation	CUST
BRA	Roxul (Bradford) Substation	CUST
KRA	Kraft Substation	CUST
WST	Westar Substation	CUST
ESS	Emerald Switching Station	TECK
TSS	Tadanac Switching Station	TECK
WAN	Waneta Generating Station	TECK
WHS	Waneta Hydro Station	TECK
WSS	Warfield Switching Station	TECK

Appendix B

DRAFT ORDER

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-XX-YY

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for Approval of 2012 – 2013 Revenue Requirements Application and
Acceptance of 2012 Integrated System Plan

BEFORE: XXX, Panel Chair/Commissioner
XXX, Commissioner
XXX, Commissioner

Month DD, 201Y

O R D E R

WHEREAS:

A. On June 30, 2011, FortisBC Inc. (FortisBC or the Company) filed pursuant to sections 59 to 61 of the *Utilities Commission Act* (the Act) an application for approval of its 2012 – 2013 Revenue Requirements;

B. Contained in the 2012 – 2013 Revenue Requirements is the Company's 2012 – 2013 Capital Expenditure Plan, filed pursuant to section 44.2(1) of the Act;

C. FortisBC also filed its 2012 Integrated System Plan pursuant to section 44.1 of the Act. The Integrated System Plan is comprised of the 2012 Long Term Capital Plan, the 2012 Long Term Resource Plan, and the 2012 Long Term Demand Side Management Plan;

D. Collectively, the 2012 – 2013 Revenue Requirements and 2012 Integrated System Plan are referred to as the Application;

E. The Application, among other things, requested pursuant to sections 59 to 61 and 89 of the Act interim and permanent rate increases of 4.0 percent effective January 1, 2012, with any difference between interim and permanent rates to be refunded to or collected from customers by way of a general rate adjustment between the effective date of the permanent rates and December 31, 2012, and a permanent rate increase of 6.9 percent effective January 31, 2013;

BRITISH COLUMBIA
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F. The Application also requested a Commission determination that the 2012 – 2013 Capital Expenditure Plan is in the public interest pursuant to section 44.2 (3) (a) of the Act and satisfies the requirements of section 45 (6), and that the Commission under section 45(2) of the Act approves the projects listed in tables 2.0, 3.0, 4.0, 5.0, 6.0 and 7.0 of the 2012 – 2013 Capital Expenditure Plan;

G. The Company also requested Commission acceptance that the 2012 Integrated System Plan is in the public interest pursuant to section 44.1 (6) of the Act;

H. The Commission issued Order No. G-XX-11 dated June 30, 2011, establishing an initial regulatory timetable for review of the Application;

I. [Description of Process]

J. The Commission has reviewed and considered the Application, the evidence, and the submissions and has determined that the Application should be approved.

NOW THEREFORE the Commission orders as follows:

1. Pursuant to sections 59 to 61 of *the Utilities Commission Act* (the Act), the following approvals are granted:

   a) Approval of the revenue requirements in the amount of $294.484 million in 2012 and $319.108 million in 2013, as set out in section 4.1 of the Application, resulting in a firm rate increase of 4.0 percent, effective January 1, 2012 and a firm rate increase of 6.9 percent effective January 1, 2013;

   b) Approval of charges between FortisBC and its affiliates regulated by the Commission based on the fully loaded cost, not including overheads charges, as set out in Section 4.3.4.18 of the Application;

   c) Approval of deferral accounts for variances from forecast of Power Purchase Expense, to be amortized into rates in 2014, and for variances from forecast of Sales Revenue, to be amortized into rates over a three-year period beginning in 2014, as described in Sections 4.1 and 5.4 of the Application;

   d) Approval of the establishment and amortization of Deferral Accounts as set out in Section 5.4 of the Application;

   e) Approval of $4.7 million of 2011 net Cost of Removal for inclusion in rate base.

2. Pursuant to section 56 of the Act, approval of depreciation rates as set out in Section 4.7.2 of the Application is granted.

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UTILITIES COMMISSION**

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3. Pursuant to section 44.2(3) of the Act, the expenditures and projects or programs for which the expenditures are requested, are determined to be in the public interest;

4. FortisBC's 2012 – 2013 Capital Expenditure Plan meets the requirements of section 45(6) of the Act;

5. Pursuant section 44.1(6) of the Act, the Company's 2012 Integrated System Plan is accepted as in the public interest.

DATED at the City of Vancouver, in the Province of British Columbia, this ___ day of (DATE).

BY ORDER

Original signed by:

Commissioner

Attachments

Appendix C

STATUS OF PAST DIRECTIVES AND NEGOTIATED SETTLEMENT PROVISIONS

Status of Past Directives and Negotiated Settlement Provisions

The following tables identify the outstanding directives contained in previous Commission orders and provisions of Negotiated Settlement Agreements, arising from past Revenue Requirements and Capital Expenditure Plan applications.

Table C.1 2011 Revenue Requirements (Order G-184-10)

	Item	Status/ Comments	Application Reference
1	**Rate Forecasts** FBC to provide a multi-year rate forecast as part of its next RRA, which includes forecast rate impacts from the Capital Expenditures Plan, Integrated System Plan, and Resource Plan. It is recognized that the Company will not be held responsible for its eventual accuracy. The 2012 application will have a forecast of expected rates for 2013, 2014, 2015 and 2016 (Appendix A, page 10).	Forecast rates for 2014 to 2016 are provided	2012-13 RRA Tab 7 page 1
2	**Power Purchase Expense** In the next RRA, FBC is to provide a discussion on their Power Purchase forecasting techniques, including the costs and benefits of the potential use of a deferral account to true up Power Purchases (Appendix A, page 7).	The Company proposes to true up Power Purchase Expense and Sales Revenue by way of deferral accounts.	2012-13 RRA Section 4.1
3	**Power Purchase Expense** FBC will treat ULE incremental power purchase costs as a power purchase expense beginning in 2012 on future ULE projects (Appendix A, page 9).	Incremental power purchases will be expensed beginning in 2012.	
4	**Load Forecast** In the 2012 RRA, FortisBC will provide more transparency in its load forecast methodology. It will also re-instate a load forecast technical committee offering participation to Commission staff and Intervenors (Appendix A, page 4).	The 2012 Load Forecast contains an expanded methodology description. A Load Forecast Technical Committee will be established subject to a Procedural Order of the Commission.	2012-13 RRA Tab 3 2012 RRA Section 8.1

	Item	Status/ Comments	Application Reference
5	**Load forecast** In the 2012 RRA, FBC will demonstrate further how they have a good grasp of their customers, especially the Residential and General Service classes of customers and how their respective UPC may be influenced by variables such as the changing housing mix, home characteristics, etc. (Appendix A, page 6).	Residential and Commercial End Use Surveys support the 2012 Long Term DSM Plan.	2012 LT DSM Plan Appendix A, Appendix B
6	**Sales Revenue** Increase Revenues by $450,000 to reflect the move of Celgar from Rate 33 to Rate 31 and true-up to actual revenues received from Celgar in 2011 at the 2011 Annual Review. The true up will flow through 2012 FBC rates (Appendix A, page 10).	Forecast variance included in Flow-through Adjustment to 2012 rates.	2012-13 RRA Section 4.8.1
7	**Sales Revenue** FBC is to treat this matter (Shaw transmission attachments) as a Z-factor and true-up any actual revenues at the 2011 Annual Review. Any true up will flow through 2012 FBC Rates (Appendix A, page 10).	Forecast variance included in Flow-through Adjustment to 2012 rates.	2012-13 RRA Section 4.8.1
8	**Accounting Policy** In its 2012 RRA, FBC should provide a description of the accounting and depreciation treatment of Major Inspection costs (Appendix A, page 8).	Accounting treatment discussion is provided.	2012-13 RRA Appendix E
9	**Depreciation** FBC to file the updated Depreciation Study in the 2012 RRA (incl. the Iowa curves and any other references used in Depreciation Study), in addition to providing explanations to any losses that are greater than $100,000 (Appendix A, page 8).	Updated Depreciation Study filed in support of 2012-13 RRA. Losses on Disposal of Property are provided.	2012-13 RRA Appendix J 2012-13 RRA Appendix E
10	**Deferred Accounts** FBC will combine these two deferral accounts [Resource Plan and Integrated System Plan] into a single Integrated System Plan (ISP) deferral account (Appendix A, page 3).	Costs of regulatory proceeding for ISP and Resource Plan combined.	2012-13 RRA Section 5.4.4
11	**Deferred Accounts** FortisBC believes that the costs are prudently incurred and are consistent with Commission Order G-168-08. All such costs should be included in rate base. However FortisBC agrees, for the purpose of this NSA, to record the AMI development costs in a non-rate base deferral account that will attract AFUDC for the 2011 Revenue Requirement, on a without prejudice basis (Appendix A, page 3).	FortisBC will file an application for a CPCN for the AMI project in 2011 and will apply to capitalize the development costs.	2012-13 RRA Section 5.4.2

	Item	Status/ Comments	Application Reference
12	**Maintenance of Assets** In the 2011 Annual Review, FBC will provide an analysis on whether any normal maintenance was delayed in 2011 into future RRAs (Appendix A, page 8).	FortisBC has not deferred any normal maintenance to future applications.	
13	**Safety Program** In the 2012 RRA, FBC should file an update to its Safety Program, along with information on various initiatives, monitoring activities and benchmarks on how to measure its success (Appendix A, page 7).	2011 Safety Plan has been filed.	2012-13 RRA Appendix K
14	**System Reliability** FBC is to develop a "plan" for addressing these worst performing feeders as part of its 2012 RRA. This plan could be a detailed justification of why the Company does not propose using this methodology for determining capital and maintenance activities (Appendix A, page 7).	FortisBC is not proposing a worst feeder program at this time.	2012 LT Capital Plan Section 3.2.2

Table C.2 2010 Revenue Requirements (Order G-162-09)

	Item	Status/ Comments	Application Reference
1	**Cost Management** FortisBC recognizes that the stakeholders in the Negotiated Settlement Process have serious concern about the escalation of customer rates due to the capital program. The Company will prudently manage costs, as it can, to mitigate future rate increases (Appendix A, page 4).	FortisBC has been mindful of the rate implications in the preparation of the Application	2013-13 RRA 2012 ISP
2	**DSM Plan** Regulatory Process concerning the Resource Plan will address compliance with Ministerial Order M271 (DSM) (Appendix A, page 6)	The Long Term Demand Side Management Plan has been filed.	2012 LT DSM Plan

Table C.3 2009 Revenue Requirements and PBR Extension (Order G-193-08)

	Item	Status/ Comments	Application Reference
1	**Regulatory Process** The 2012 application to be reviewed by oral public hearing (Appendix A, page 11)	The Company will comply with the NSA provision if it is the preference of the Commission and Interveners.	2012-13 RRA Section 8.1
2	**Deferred Charges** If and when the Vaseux Lake incident becomes a contingent loss under the CICA definition, FortisBC will commence reporting the amount in the financial statements and in the non-rate based, non-interest bearing deferral account. The disposition of this deferral account should be addressed in a separate application by FortisBC to the Commission following the court decision (Appendix A, page 4).	There are currently no costs estimated.	
3	**Deferred Charges** ROW Encroachment - Hold amount in deferral account pending court decision. If court decision is favourable, record recovered cost to the deferral account, then amortize the residual into rates (Appendix A, page 4).	Dispute remains unresolved.	2012-13 RRA Section 5.4.5
4	**Generation Life Extension** FortisBC to provide a business case analysis of any continuing benefits from future generator upgrades and life extensions. (4 units at Upper Bonnington) (Appendix A, page 7).	FortisBC will file a business case prior to commencing the Old Unit Repowering Project.	
5	**Stakeholder Engagement** FortisBC should have meaningful engagement of stakeholders before applications are submitted to the BCUC. FortisBC will engage in meaningful stakeholder engagement before the Rate Design Application (RDA), Cost of Service, Advanced Meter Infrastructure, DSM Study and Net Metering applications are submitted to the BCUC (Appendix A, page 5).	FortisBC carried out a comprehensive consultation program prior to filing.	2012 LT Capital Plan Appendix K
6	**Regulatory Process** The 2012 oral public hearing or the next Performance Based Rate Application review process will examine the criteria for meeting performance standards (Appendix A, page 10).	Performance Standards will be addressed in any future PBR Plan.	

Table C.4 2008 Revenue Requirements (Order G-147-07)

	Item	Status/ Comments	Application Reference
1	**Deferred Charges** FortisBC will continue to provide detail on the Revenue Protection program annually (Appendix A, page 5).	In 2012, Revenue Protection activities are included in O&M expense. Activities for 2011 are described in the Application.	2012-13 RRA Section 5.4.5
2	**Related Party Transactions** Disclosure of related party transactions will be a standard item for future revenue requirements applications (Appendix A, page 5).	2010 Related Party Transactions Report filed.	2012-13 RRA Appendix L

Table C.5 2006 Revenue Requirements and PBR Plan (Order G-58-06)

	Item	Status/ Comments	Application Reference
1	**Capitalized Overheads** The parties acknowledge that the Capitalized Overhead Policy is premised on the extensive capital program that FortisBC is currently undertaking, therefore the Company's Capitalized Overhead methodology will be reviewed at the end of the PBR term(Appendix I, page 24-25).	FortisBC reviewed its Capitalized Overheads methodology and recommends that the proportion of gross O&M capitalized remain unchanged for 2012 - 2013.	2012-13 RRA Section 4.4
2	**DSM Amortization** Amortization of DSM expenditures, beginning in 2001, will be consistent with the practice of BC Hydro, as described in Issue 15 of the 2006 Revenue Requirements NSA (Appendix I, page 22).	BC Hydro continues to amortize DSM expenditures over ten years. FortisBC is not proposing a change to the amortization period for DSM expenditures.	2012-13 RRA Section 5.4.1
3	**Depreciation Expense** The Company and the Participants hold differing views on negative salvage values in the depreciation study. The Parties agree to defer analysis of the issue of negative net salvage value in the depreciation study for the term of the PBR ending in 2008 or 2009 (Appendix I, page 9).	The Company does not propose a provision for negative salvage in this Application as it would result in a significant increase to rates.	2012-13 RRA Section 4.7.3

	Item	Status/ Comments	Application Reference
4	**Operating Savings** For information purposes only, operating savings claimed in the 2006 and future CEP and CPCN applications will be tabulated and presented at each Annual Review (Appendix I, page 22).	To be included with 2011 Annual Review materials.	

Table C.6 2011 Capital Expenditure Plan (Order G-195-10)

	Item	Status/ Comments	Application Reference
1	**Accounting Treatment** The Commission Panel directs FortisBC to prepare and file a report detailing a list of Transmission and Distribution Capital Sustaining programs (with the exception of the programs discussed in Section 7.2 below) each referencing specific sections of the Company's Capitalization Policy guidelines, along with a discussion on the Company's interpretation of why it considers each program to be capital in nature. In addition, the Commission Panel directs FortisBC to include a discussion and analysis on its determination of the $1,000 minimum capitalizable amount, as stated in its current Capitalization Policy, along with a detailed assessment on the justification for this minimum and an assessment of the minimum capitalizable amounts of comparable utilities within British Columbia and other jurisdictions. This report is to be filed to the Commission within 90 days from the date of this Decision (page 65).	Reporting date varied by Order G-38-11.	2012-13 RRA Appendix M
2	**DSM Programs** The Commission Panel therefore directs FortisBC to include the topics of energy efficiency and incentive opportunities in its consultation with the Irrigation Rate Class (page 58).	FortisBC has committed to engaging the Irrigators in meaningful consultation regarding new or modified irrigation DSM programs.	2012 LT DSM Plan Section 3.4.2

	Item	Status/ Comments	Application Reference
3	**Capital Expenditures** The Commission Panel directs FortisBC to provide information, in its next revenue requirement application, on how it plans to narrow the variance between approved and actual capital expenditures to ensure that rates charged to customers and the return received by shareholders are both fair and equitable (page 70).	The Company's report on this subject is included in this filing.	2012-13 RRA Appendix N

Appendix D

FINANCIAL STATEMENT RECONCILIATIONS FROM FORTISBC 2010 ANNUAL REPORT TO BCUC

APPENDIX A
RECONCILIATION OF FINANCIAL STATEMENTS

STATEMENT OF EARNINGS, CORPORATE AND REGULATORY
YEAR ENDED DECEMBER 31, 2010

	Corporate (external)		Regulated
		($000s)	
REVENUE			
Sale of power	248,821	(2,030)	246,791
Other	8,093	(1,641)	6,453
	256,914	(3,670)	253,244
EXPENSES			
Operating and Maintenance	37,877	(1,258)	36,619
Power Purchases	72,975	(1,012)	71,964
Wheeling	4,050	-	4,050
Property taxes	12,581	(343)	12,238
Water fees	9,365	(109)	9,256
Depreciation & Amortization of Deferreds	41,620	151	41,771
	178,468	(2,571)	175,897
EARNINGS FROM OPERATIONS	78,446	(1,099)	77,347
INTEREST EXPENSE			
Long-term debt	36,128	(1,954)	34,174
Short-term debt	717	246	964
Amortization of deferred financing costs	389	(389)	-
Allowance for funds used during construction	(4,733)	4,733	-
	32,501	2,637	35,138
REGULATORY INCENTIVE ADJUSTMENTS	-	(629)	(629)
EARNINGS BEFORE INCOME TAXES	45,945	(3,107)	42,838
INCOME TAXES	4,185	359	4,544
NET EARNINGS	**41,760**	**(3,466)**	**38,294**

Note: Minor differences due to rounding.

RECONCILIATION OF STATEMENT OF EARNINGS
CORPORATE TO REGULATORY

	($000s)
Sale of Power	248,821
Walden Power Partnership	(2,030)
Regulatory	246,791
Other Revenue	8,093
Reclassify Incentive Adjustments	(629)
Reclass sale of surplus power	(1,012)
Regulatory	6,453
Operating and Maintenance Expense	37,877
Non Regulated	(452)
Walden Power Partnership	(806)
Regulatory	36,619
Power Purchases	72,975
Reclass sale of surplus power	(1,012)
Regulatory	71,964
Property Taxes	12,581
Walden Power Partnership	(343)
Regulatory	12,238
Water Fees	9,365
Walden Power Partnership	(109)
Regulatory	9,256

	($000s)
Depreciation & Amortization of Deferreds	41,620
Warfield Garage Expansion (non-reg)	(14)
Walden Power Partnership	(224)
Reclass Amortization of Deferred Financing Costs	389
Regulatory	41,771
Long Term Interest Expense	36,128
Reclass to Short Term Interest	(1,640)
Walden Power Partnership	(315)
Regulatory	34,174
Short Term Interest Expense	717
Reclass from Long Term Interest	1,640
Reclass CWIP to Non-Regulated entity	(1,393)
Regulatory	964
Amortization of Deferred Financing Costs	389
Reclass to Depreciation & Amortization	(389)
Regulatory	-
AFUDC	(4,733)
Reclass AFUDC to Non Regulated	4,733
Regulatory	-
Incentive Adjustments	
Amortization of Prior Year Incentives	(2,690)
Current Year Incentive Adjustments	2,061
Regulatory	(629)
Income Tax Expense	4,185
Walden Power Partnership & Non-Reg. Affiliates	359
Regulatory	4,544

Note: Minor differences due to rounding.

BALANCE SHEET, CORPORATE AND REGULATORY
AS AT DECEMBER 31, 2010

	Corporate (external)		Regulated
		($000s)	
ASSETS			
Plant and Equipment & Intangibles	1,391,655	81,856	1,473,511
Less accumulated depreciation	(301,439)	(21,765)	(323,204)
	1,090,216	60,091	1,150,307
Capital Lease Asset (non-rate base)	-	20,644	20,644
Asset Retirement Obligation (non-rate base)	-	2,879	2,879
Other Assets	11,383	5,314	16,698
Regulated Assets	119,310	(119,310)	-
Non-Rate Base Assets	-	111,772	111,772
	130,694	21,299	151,993
Goodwill	1,209	(1,209)	-
Current Assets			
Cash	18	(18)	-
Accounts receivable	45,843	(14,527)	31,316
Unbilled revenue	-	17,783	17,783
Prepaid expenses	1,119	(24)	1,094
Future income taxes	999	(999)	-
Other assets	566	(566)	-
Inventory	467	-	467
Regulated assets	311	(311)	-
	49,323	1,338	50,660
TOTAL ASSETS	**1,271,441**	**81,520**	**1,352,961**
CAPITAL AND LIABILITIES			
Capitalization			
Shareholder's Equity			
Common shares	201,851	(21,729)	180,122
Retained earnings	231,816	6,608	238,424
Total Shareholder's Equity	433,667	(15,121)	418,546
Long-Term Debt			
Secured debentures	40,000	-	40,000
Unsecured debentures	600,000	-	600,000
Debt issue costs	(6,030)	6,030	-
Long Term WPP Mortgage	1,943	(1,943)	-
Total Long-Term Debt	635,913	4,087	640,000
Contributions in Aid of Construction	-	93,763	93,763
Obligation under Capital Lease and Other (non-rate base)	31,893	(4,901)	26,992
Other Post-Retirement Benefit Liability (non-rate base)	14,121	-	14,121
Asset Retirement Obligation (non-rate base)	-	3,219	3,219
Future income taxes (non-rate base)	92,240	(2,196)	90,044
Regulated Liability Long Term	1,082	(1,082)	-
	139,336	(4,960)	134,376
Current Liabilities			
Accounts payable and accrued liabilities	50,610	7,121	57,731
Current portion of debt	2,049	(2,049)	-
Accrued interest	4,545	-	4,545
Income Taxes Payable	2,117	343	2,460
Bank Loans	-	1,122	1,122
Regulated liability	2,771	(2,771)	-
Future income taxes	433	(15)	418
	62,525	3,751	66,276
TOTAL CAPITAL AND LIABILITIES	**1,271,441**	**81,520**	**1,352,961**

Note: Minor differences due to rounding.

RECONCILIATION OF BALANCE SHEET

AS AT DECEMBER 31, 2010

ASSETS	($000s)
Plant and Equipment & Intangibles	1,391,655
Reclassify CIACs	136,400
Warfield Garage Expansion	(252)
Capital Lease Asset (non-rate base)	(27,689)
Walden Power Partnership	(23,424)
Asset Retirement Obligation (non-rate base)	(3,178)
Regulated	1,473,511
Accumulated Depreciation	(301,439)
Reclassify Amortization of CIACs	(42,636)
Capital Lease Accum Dep (non-rate base)	7,045
Warfield Garage Expansion	90
Walden Power Partnership	13,436
Asset Ret. Obligation Accum Dep (non-rate base)	299
Regulated	(323,204)
Capital Lease Asset (non-rate base)	
Capital Lease Asset	27,689
Capital Lease Accum Dep	(7,045)
Regulated	20,644
Asset Retirement Obligation (non-rate base)	
Asset Retirement Obligation (non-rate base)	3,178
Asset Ret. Obligation Accum Dep (non-rate base)	(299)
Regulated	2,879
Deferred Charges	11,383
Reclass Accounts Receivable	(2,643)
Reclass Current Regulated Assets	311
Reclass LT Regulated Assets	7,539
Reclass Debt Issue Costs	5,329
Reclass LT Liability	(2,069)
Reclassify Current Regulated Liability	(3,153)
Regulated	16,698
Regulated Assets	119,310
Reclass Deferred Charges	(7,539)
Non-Rate Base Assets	(111,771)
Regulated	-
Goodwill	1,209
Non Regulated	(1,209)
Regulated	-
Cash	18
Walden Power Partnership	(18)
Regulated	-
Accounts Receivable	45,843
Reclassify Unbilled Revenue	(17,783)
Reclass Other LT Assets	2,643
Reclass Current Portion Other Assets	566
Non-Regulated	118
Walden Power Partnership	(71)
Regulated	31,316
Unbilled Revenue	-
Reclass Accounts Receivable	17,783
Regulated	17,783
Prepaid Expenses	1,119
Walden Power Partnership	(24)
Regulated	1,094
Future Income Taxes	999
Reclass Liability	(999)
Regulated	-
Other Assets	566
Reclass Accounts Receivable	(566)
Regulated	-
Current Portion Regulated Assets	311
Reclass to Deferred Charges	(311)
Regulated	-

CAPITAL AND LIABILITIES	($000s)
Retained Earnings	231,816
Non Regulated	6,608
Regulated	238,424
Common Shares	201,851
Non Reg Share Capital	(21,729)
Regulated	180,122
Debt Issue Costs	(6,030)
Reclass to Deferred Charges	5,328
Non-Regulated (effective interest method)	702
Regulated	-
Contributions in Aid of Construction	
Reclassify Plant & Equipment	136,400
Reclassify Amortization of CIAC	(42,636)
Regulated	93,763
Obligation under Capital Lease and Other (non-rate base)	31,893
Reclass to Deferred Charges	(2,069)
Reclass from Current Liabilities	386
Asset Ret. Obligation (non-rate base)	(3,219)
Regulated	26,992
Asset Retirement Obligation (non-rate base)	
Asset Ret. Obligation (non-rate base)	3,219
Regulated	3,219
Future Income Taxes	92,240
Reclass Asset Portion	(999)
Walden Power Partnership	(1,212)
Princeton Light & Power Regulated	(418)
Add Back Current Regulated F.I.T.	433
Regulated	90,044
Accounts Payable and Accrued Liabilities	50,610
Walden Power Partnership	(308)
Intercompany Accounts	7,894
Reclass to Capital Lease Obligation	(386)
Non Regulated	(80)
Regulated	57,731
Current Portion of Debt	2,049
Reclass Current Portion Bank Loan	(1,122)
Walden Power Partnership	(927)
Regulated	-
Bank Loans	-
Reclass Current Portion LT Debt	1,122
Regulated	1,122
Income Taxes Payable	2,117
Walden Power Partnership	(47)
Non Regulated	390
Regulated	2,460
Regulatory Liability Long Term	1,082
Regulated (Effective Interest Method)	(702)
Regulated Long Term Liability	(380)
Regulated	-
Regulated Liability	2,771
Reclass to Deferred Charges	(2,771)
Regulated	-
Non-Rate Base Assets	
Other Post-Retirement Benefits	14,121
BTS Lease Costs	5,098
Trail Office Lease Costs	1,249
Future Income Tax	90,044
Asset Ret. Obligation (non-rate base)	340
AMI Feasibility Study	920
Regulated	111,772

Note: Minor differences due to rounding.

Appendix E

ACCOUNTING CHANGES: US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (US GAAP) AND REQUEST FOR NON-RATE BASE DEFERRALS

INTRODUCTION

The purpose of this Appendix is twofold:

A. First, to provide the background and update on Rate-Regulated Accounting standards, as well as provide an overview of FortisBC's application to the BCUC to request adopting US GAAP for regulatory purposes.

B. Second, the Company is requesting that the Commission acknowledge the timing differences between regulatory reporting and external financial reporting as non-rate base deferrals (regulatory assets and liabilities) with the expectation that these amounts will collected or refunded to customers in future rates. For non-rate base items previously approved for deferral, the Company has updated its forecast amounts for 2012 and 2013. For new deferral accounts, the Company has requested specific approval to recognize the non-rate base deferral account.

A. Background and FortisBC Application to Adopt US GAAP

In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed that International Financial Reporting Standards (IFRS) would replace Canadian Generally Accepted Accounting Principles (CGAAP) for publicly accountable enterprises for financial periods beginning on or after January 1, 2011.

Although the status of accounting for Rate-Regulated Activities was initially uncertain under IFRS, during late 2008 and throughout 2009 there was significant momentum in support of recognizing regulated assets and liabilities under IFRS, culminating in the release of an Exposure Draft on Rate-Regulated Activities in July 2009 (2009 ED) that would have allowed the recognition of regulated assets and liabilities.

Starting in mid 2010, a series of events transpired which resulted in a significantly reduced probability that IFRS would allow the recognition of regulated assets and liabilities:

- In July 2010, the International Accounting Standards Board (IASB) met to review the 2009 ED. At this meeting, no decision was made on whether regulatory assets or regulatory liabilities could be recognized under the current IFRS framework. The IASB stated there would not be a standard until at least the second half of 2011 and no transitional relief was provided.

- Also in July 2010, and in light of the lack of progress on a Rate-Regulated Activities standard under IFRS, the AcSB issued an Exposure Draft (2010 ED) which provided a two year optional IFRS transitional deferral for Canadian rate-regulated entities (i.e. January 1, 2013 adoption date).
- In September 2010, the IASB reconfirmed its earlier view that matters associated with Rate-Regulated Activities could not be resolved quickly. The IASB decided to include in its public consultation on its future agenda a request for views on what form a future project might take, if any, to address Rate-Regulated Activities. The project was removed from the IASB's active work plan.
- Also in September 2010, the AcSB responded to the IASB uncertainty by withdrawing the two-year optional IFRS transitional deferral for rate-regulated entities and publishing a Decision Summary permitting a one year deferral option (i.e. January 1, 2012 adoption date) instead. FortisBC elected to take the deferral option of one year. The reduction from a two year to a one year deferral option significantly decreased the likelihood of IFRS including a Rate-Regulated Activities standard prior to adoption of IFRS by Canadian rate-regulated entities.
- In December 2010, the international accounting firms communicated a general consensus to the Canadian rate-regulated utility industry that they will not generally support the recognition of regulated assets and liabilities under existing IFRS.

As a result of these developments, the recognition of regulated assets and liabilities has been prohibited under existing IFRS for the foreseeable future.

Overview of Application to Adopt US GAAP

During the fourth quarter of 2010, FortisBC started to focus its efforts on alternatives to resolve the significant issues related to adopting IFRS that do not allow recognition of regulated assets and liabilities. Due primarily to the continued uncertainty around the timing and eventual adoption of a Rate-Regulated Activities standard under IFRS, management of FortisBC, in connection with its parent company Fortis Inc., began reviewing the option of adopting US GAAP instead of IFRS.

The Company believes continued recognition of regulatory assets and liabilities best reflects the effect regulatory activities have on financial position and the economic realities of the business and the regulatory model the Company operates under. It is FortisBC's understanding that the only existing set of accounting standards that currently would allow for regulatory assets and liabilities to continue to be recognized is US GAAP.

On February 9, 2011, FortisBC submitted an application to the BCUC requesting approval to adopt US GAAP effective January 1, 2012, for the calculation of cost of service, revenue requirements, rate base, and the preparation of regulatory schedules and filings. At the time of finalizing the 2012-2013 Revenue Requirements Application (2012-13 RRA), the US GAAP application had not been approved.

B. Request for Regulatory Approval of Non-Rate Base Deferrals (Regulatory Assets and Liabilities)

For non-rate base deferrals previously approved for recognition the Company has updated the 2012 and 2013 forecast deferral amounts. For new non-rate base deferral accounts, the Company is requesting that the Commission acknowledge the timing differences between regulatory reporting and external financial reporting as non-rate base deferrals (regulatory assets and liabilities) with the expectation that these amounts will be collected or refunded to customers in future rates.

This section of the Appendix describes the non-rate base deferral accounts that result from differences in the regulatory reporting for this 2012-13 RRA and the accounting policies required for external financial reporting. The accounting policies used for external financial reporting purposes and the resulting creation of non-rate base deferral accounts, are generally consistent under both Part V of the Canadian Institute of Chartered Accountants Handbook – *Pre-Changeover Canadian Generally Accepted Accounting Principles* and US GAAP. The discussion related to the application of US GAAP and the cessation of pre-changeover CGAAP beginning in 2012 is included in Tab 2, Section 2.0 of this Application.

When assessing the recognition of a regulatory asset or liability under pre-changeover CGAAP or US GAAP, an entity considers the probability that a regulator will allow particular costs. In assessing the probability of recovery, the following factors may be considered as evidence that a regulatory asset or liability may be recognized:

- Statutes or regulations that specifically provide for the recovery of the cost in rates;
- Formal approval from the regulator specifically authorizing recovery of the cost in rates;

- Previous formal approvals from the regulator allowing recovery for substantially similar costs (precedents) for a specific entity or other entities in the same jurisdiction; and
- Uniform regulatory accounting guidance providing for the accounting treatment of various costs that the regulator typically follows in setting rates.

The regulatory acceptance of non-rate base deferral items and the acknowledgment that the deferrals are based on timing differences, which will be collected from or refunded to customers in the future, will provide further support for the items to be recognized as regulatory assets or liabilities for external financial reporting purposes under US GAAP in 2012 and 2013, similar to pre-changeover CGAAP. This request is consistent with FortisBC's 2009, 2010 and 2011 Revenue Requirements Applications which were prepared under pre-changeover CGAAP in anticipation of transition to IFRS, when regulatory assets and regulatory liabilities were still expected to be recognized by IFRS. Regulatory approval or acknowledgement of these non-rate base deferral accounts now would not permit continued recognition under current IFRS as rate-regulated deferral accounting is not permitted.

Accounting policies that FortisBC has been required to adopt under pre-changeover CGAAP has had an impact on the timing and cost of service amounts included in revenue requirements. In such cases where these accounting changes were not incorporated into customer rates, a non-rate base deferral (regulatory asset or liability) has been used to account for the timing difference. The policies and the resulting creation of non-rate base deferrals described in the following sections of this Appendix reiterate certain accounting treatments currently used under pre-changeover CGAAP which are also required under a US GAAP adoption scenario. Any further accounting treatments that would be required as a result of adopting US GAAP which would create new non-rate base deferrals are also identified in the following sections.

The net impact of these accounting changes on revenue requirements in 2012 and 2013 is not significant as the Company moves towards US GAAP compliant accounting policies. For existing non-rate base deferrals that have been previously approved for recognition, the Company has updated the forecast 2012 and 2013 deferral amount. To the extent that a certain accounting treatment has not been integrated into the Company's regulatory accounting model, a request for specific regulatory approval of a non-rate base deferral (regulatory asset or liability) account has been included in this Appendix. These deferrals have been summarized in the table below, which is also included in the financial schedules in Tab 7, Schedule 1A.

The table has been arranged with Other Assets and Other Liabilities representing the items required to be recognized under both pre-changeover CGAAP and US GAAP, with the exception of pension and other post-employment benefits, which are required to be recognized under a US GAAP scenario only. The Regulatory Assets and Regulatory Liabilities represent the cumulative effect of not recognizing the offsetting amount in cost of service. The Reference column corresponds to the description of each non-rate base item following the table.

Table E.1 Regulatory Assets and Liabilities

Ref		BCUC Order No. [1]	Forecast 2011	Forecast 2012	Forecast 2013
			Asset / (Liability) ($000s)		
	Assets				
	Regulatory Assets				
1	Deferred Income Tax Regulatory Asset	G-37-84, G-193-08	101,089	113,019	126,611
2	Brilliant Terminal Station Lease Costs	G-2-04, G-193-08	5,424	5,715	5,970
3	Brilliant Power Purchase Agreement Lease Costs		-	60,299	67,225
4	Asset Retirement Obligation	G-184-10	1,022	1,706	2,392
5	Trail Office Building Lease Costs	G-41-93, G-193-08	1,104	973	-
6	Other Post-Employment Benefits Regulatory Asset		-	5,764	5,468
7	Defined Benefit Pension Regulatory Asset		-	28,800	27,537
9	Uncertain Tax Positions		-	-	-
			108,639	216,275	235,203
	Other Assets				
2	Brilliant Terminal Station Capital Lease Asset	G-2-04, G-193-08	19,932	19,220	18,508
3	Brilliant Power Purchase Agreement Capital Lease Asset		-	205,813	201,081
4	Asset Retirement Costs	G-184-10	2,281	1,683	1,085
8	Financing Costs Under Effective Interest Method	G-184-10	758	796	804
10	Embedded Derivative Valuation Adjustment		-	-	-
			22,971	227,512	221,479
	Total Non-Rate Base Assets		**131,610**	**443,787**	**456,681**
	Liabilities				
	Regulatory Liabilities				
8	Financing Costs Under Effective Interest Method	G-184-10	(758)	(796)	(804)
10	Embedded Derivative Valuation Adjustment		-	-	-
			(758)	(796)	(804)
	Other Liabilities				
1	Deferred Income Tax Liability	G-37-84, G-193-08	(101,089)	(113,019)	(126,611)
2	Brilliant Terminal Station Capital Lease Liability	G-2-04, G-193-08	(25,356)	(24,935)	(24,478)
3	Brilliant Power Purchase Agreement Capital Lease Liability		-	(266,112)	(268,306)
4	Asset Retirement Obligation	G-184-10	(3,303)	(3,389)	(3,478)
5	Trail Office Building Lease Liability	G-41-93, G-193-08	(1,104)	(973)	-
6	Other Post-Employment Benefits Liability		-	(5,764)	(5,468)
7	Defined Benefit Pension Liability		-	(28,800)	(27,537)
9	Uncertain Tax Positions		-	-	-
			(130,852)	(442,991)	(455,877)
	Total Non-Rate Base Liabilities		**(131,610)**	**(443,787)**	**(456,681)**
	Net Non-Rate Base Assets		**-**	**-**	**-**

[1] Commission Order reference is indicative of previous BCUC approval of these amounts as non-rate base deferral accounts.

1. Deferred Income Tax

Current Practice:

FortisBC follows the taxes payable method of accounting for income taxes on regulated earnings in accordance with Commission Order G-37-84:

> *"The Commission has found that the public interest will best be served with a change to "flow-through" accounting for income tax purposes for the Applicant. The change is to occur effective August 1, 1984. The balance of deferred income taxes on the books of the Applicant as at July 31, 1984 will remain and be included in the capital structure as zero cost capital."*

In addition, certain regulatory assets and deferred charges are recorded net of their income tax impact, with the offset charged to income tax expense. Under this methodology, customer rates do not include the recovery of deferred income taxes related to temporary timing differences between the tax basis of recording regulated assets and liabilities versus their carrying amounts for accounting purposes, other than for the regulatory assets and deferred charges recorded net of their income tax impacts.

The deferred income tax liability arises primarily due to the differences between the depreciation rates approved by the Commission for rate setting purposes compared with the rates of depreciation allowed for tax calculation purposes. As a result of FortisBC's forecast capital activity, the deferred income tax liability will continue to increase due to these tax timing differences. The effect of the increasing deferred income tax liability is evident in the 2012-13 RRA where the effective tax rate is approximately 11.8 percent in 2012 and 14.1 percent in 2013 compared with the statutory rate of 25.0 percent. The lower effective tax rate is expected to continue and provide a benefit to current customers over the foreseeable future. The deferred income tax balance will eventually be paid to Canada Revenue Agency and included in customer rates in future periods when the Company's timing differences reverse.

US GAAP Guidance:

ASC 980-740-55-1, *Regulated Operations - Income Taxes*, requires a regulated entity to record a deferred income tax liability with a corresponding offset to regulatory assets for amounts expected to be included in approved rates charged to customers in the future. Therefore the relevant US GAAP guidance is generally consistent with pre-changeover CGAAP.

2012-13 RRA Update:

This item has been previously approved as a non-rate base deferral account pursuant to Commission Orders G-37-84 and G-193-08. FortisBC has forecast year-end balances of approximately $113.0 million in 2012 and $126.6 million in 2013. This deferral account will offset the otherwise recognized deferred income tax expense resulting from the deferred income tax liability arising on the Company's regulated operations.

2. Brilliant Terminal Station (BTS) Capital Lease

Current Practice:

FortisBC entered into a long-term lease of the BTS in 2003, which was required to be accounted for as a capital lease under pre-changeover CGAAP. However, for regulatory purposes it was approved to be treated as an operating lease in accordance with Commission Order G-2-04:

> *"The Commission approves for Aquila the variance from GAAP to treat the lease obligation for the Brilliant Terminal Station agreement as an operating lease, rather than a capital lease. Approval is granted to Aquila for the establishment of a deferral account for the Brilliant Terminal Station Expense."*

A timing difference exists between the recovery of the capital cost of the BTS, the cost of financing the BTS Obligation and the related operating costs, and the BTS lease payments made on a cash basis (as an operating lease).

US GAAP Guidance:

The substance of the BTS lease would continue to be classified as a capital lease under ASC 840-10-25-1, *Leases-Recognition*. Therefore the relevant US GAAP guidance is generally consistent with pre-changeover CGAAP.

2012-13 RRA Update:

This item has been previously approved as a non-rate base deferral account pursuant to Commission Orders G-2-04 and G-193-08. FortisBC has forecast year-end balances of approximately $5.7 million in 2012 and $6.0 million in 2013 to account for the timing differences of recording the BTS as a capital lease for external financial reporting and as an operating lease for regulatory reporting.

3. Brilliant Power Purchase Agreement (BPPA) Capital Lease

Current Practice:

In accordance with Commission Order E-7-96, all costs associated with purchasing power from the Brilliant Plant under the BPPA are recorded as power purchase expenses. Interpretive guidance under pre-changeover CGAAP EIC-150, *Determining Whether an Arrangement Contains a Lease*, would require an assessment of whether the BPPA constitutes a lease arrangement. However, the abstract was issued in 2004 and required prospective application to arrangements agreed to after the date of the abstract. Therefore, the BPPA that was executed in 1996 was exempt from analysis.

US GAAP Guidance:

The substance of the BPPA, pending auditor approval, is expected to be an arrangement that contains a lease under ASC 840-10-15-6, *Leases-Arrangements That Qualify as Leases*. This guidance is effective for any leases or amendments to leases that occur after May 28, 2003. There was an amendment to the BPPA on April 1, 2004 which therefore requires the arrangement to be accounted for as a lease on that date. The nature of the lease arrangement would be classified as a capital lease because the present value of the minimum lease payments made by FortisBC represents the recovery of the entire amount of the initial investment in the Brilliant Plant by the owner over the term of the arrangement.

2012-13 RRA Request:

Under a US GAAP adoption scenario, FortisBC is required to record the BPPA as a capital lease retroactively back to April 1, 2004. The effect on the Company's balance sheet is the initial recognition of a capital lease asset in the amount of approximately $230 million (depreciated value of $205.8 million in 2012 and $201.1 million in 2013) with an offsetting capital lease obligation for an equivalent amount (amortized value of $266.1 million in 2012 and $268.3 million in 2013). This arrangement would also qualify as a capital lease under IFRS, specifically IFRIC 4 *Determining Whether an Arrangement Contains a Lease,* and IAS 17 *Leases.*

Each year subsequent to initial capitalization, the amount previously determined as power purchases under pre-changeover CGAAP will be replaced by depreciation on the finance lease asset and interest and accretion expense on the finance lease obligation. These amounts differ from the amount paid under the BPPA, and as a result approval of a non-rate base deferral account of approximately $60.3 million in 2012 and $67.2 million in 2013 is requested for the timing differences to be recovered from customers through future rates over the life of the BPPA. Recognizing the BPPA as a capital lease will affect the timing of amounts recorded as expense, however once the BPPA expires the total amount paid under the agreement as power purchases would equal the total amount expensed related to the capital lease.

4. Asset Retirement Obligation (ARO)

Current Practice:

FortisBC has recognized an asset retirement cost in property, plant and equipment and an offsetting ARO liability in its external financial statements prepared under pre-changeover CGAAP. The ARO relates to the removal costs of Polychlorinated Biphenyls (PCBs) in station equipment and distribution equipment as determined under Environment Canada PCB Regulations. The costs related to the PCB removal program are included in the Company's 2012-13 Capital Plan under the project "PCB Environmental Compliance" in Tab 7, Table 1 – A – 1.

The non-rate base regulatory asset, previously approved by Commission Order G-184-10, relates to the depreciation expense on the capitalized asset retirement cost and the accretion expense on the ARO liability that will be recognized between 2011 and 2025. This non-rate base asset will begin to unwind into regulated rate base when PCB Environmental Compliance costs are capitalized into plant in service beginning in 2012 and depreciated into customer rates, beginning in 2013.

US GAAP Guidance:

ASC 410-20-25, *Asset Retirement and Environmental Obligations-Recognition*, also requires recognition of all legal obligations associated with the retirement of tangible long-lived assets as an ARO. The measurement requirements are similar under pre-changeover CGAAP; therefore the relevant US GAAP guidance is generally consistent with pre-changeover CGAAP.

2012-13 RRA Update:

This item has been previously approved as a non-rate base deferral account pursuant to Commission Order G-184-10. FortisBC has forecast year-end balances of approximately $1.7 million in 2012 and $2.4 million in 2013 related to the ARO timing differences for the PCB removal program. The difference will begin to unwind into regulated rate base when PCB

Environmental Compliance costs are capitalized into plant in service and depreciated into customer rates.

5. Trail Office Building Lease

Current Practice:

Under a sale-leaseback agreement, on September 29, 1993 the Company began leasing its Trail, BC office building for a term of 30 years. The Company is accounting for the lease as an operating lease. The terms of the agreement require increasing stepped lease payments during the lease term. As approved by way of Commission Order G-41-93, the Company recovers the Trail office lease payments from customers and records the lease costs on a cash basis. Under pre-changeover CGAAP, the lease payments are to be levelized. The difference is recorded as a regulatory asset, which represents the deferred portion of the lease payments that is expected to be recovered from customers in future rates as the stepped lease payments increase.

US GAAP Guidance:

ASC 840-20-25-1, *Leases - Recognition*, states that lease payments are charged to expense by lessees over the lease term as they become payable. If rental payments are not made on a straight-line basis, rental expense nevertheless shall be recognized on a straight-line basis. Therefore the relevant US GAAP guidance is generally consistent with pre-changeover CGAAP.

2012-13 RRA Update:

This item has been previously approved as a non-rate base deferral account pursuant to Commission Orders G-41-93 and G-193-08. FortisBC has forecast a year-end balance of approximately $1.0 million in 2012 to account for the timing differences of recording the Trail office lease expenses on a straight line basis for external financial reporting and on the cash basis for regulatory reporting. The Company is anticipating exercising an option to purchase the Trail office on September 30, 2013 and therefore the deferral account representing the timing differences in recognizing lease expense would no longer be required at the end of 2013.

6. Employee Future Benefits – Other Post-Employment Benefits (OPEB)

Current Practice:

Benefits earned by employees are actuarially determined as the employees provide service. All accrued obligations for employee post-employment benefits are determined by independent actuaries using the projected benefits method prorated on service. Unrecognized transitional obligations, together with adjustments arising from changes in assumptions and the excess of cumulative net actuarial gains or losses over 10 per cent of the benefit obligation (i.e. corridor approach), are amortized on a straight-line basis over the Expected Average Remaining Service Life (EARSL) of the employees covered by the plan. The plan is unfunded, and currently FortisBC has recognized a credit to rate base to reflect the full accrual cost of other post employment benefits beginning in 2005 and phase-in of the transitional amount as at that date pursuant to Commission Order G-52-05.

US GAAP Guidance:

ASC 715-60-25, *Defined Benefit Plans, Other Post-Retirement - Recognition*, requires the funded status of a defined benefit plan (measured as the OPEB liability since the plan is unfunded) to be recognized in the balance sheet with the corresponding adjustment recorded in Accumulated Other Comprehensive Income (AOCI). Rather than recognize this amount in AOCI or as a rate base deferral account, the Company is requesting regulatory recognition and acknowledgement of a non-rate base deferral account to accumulate these amounts. Under current US GAAP, the amount in AOCI is recycled through the OPEB net benefit cost, similar to pre-changeover CGAAP, which is why the amount in AOCI is not requested to be included as a rate base account subject to amortization.

2012-13 RRA Request:

Under a US GAAP adoption scenario, FortisBC requests approval of a non-rate base deferral account in the amount of approximately $5.8 million in 2012 and $6.1 million in 2013. The adjustment recognizes any unamortized gains and losses due to the application of the corridor approach and any remaining unamortized transitional obligation. All of these components are expected to be collected from customers in future periods when recognized through the periodic net benefit cost.

7. Employee Future Benefits – Defined Benefit Pension

Current Practice:

Benefits earned by employees are actuarially determined as the employees provide service. The Company accrues its obligations under employee benefit plans and the related costs, net of plan assets. Unrecognized transitional obligations, together with adjustments arising from plan amendments, changes in assumptions and the excess of cumulative net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the fair value of the plan assets (i.e. corridor approach), are amortized on a straight-line basis over the Expected Average Remaining Service Life (EARSL) of the employees covered by the plans. The Company's policy is to fund the defined benefit plans on an actuarial basis in accordance with pension standards legislation, in order to accumulate assets sufficient to meet the benefits to be paid. Currently, FortisBC is in a prepaid position indicating that past funding has been in excess of the actual net benefit cost recorded.

US GAAP Guidance:

ASC 715-30-25, *Defined Benefit Plans, Pension - Recognition*, requires the funded status of a defined benefit plan, all accumulated unrecognized losses (gains) and all unrecognized prior service costs (credits) to be recognized in Accumulated Other Comprehensive Income (AOCI) with an equal offset booked against the prepaid pension cost so that the actual funded status (difference between the fair value of plan assets and the benefit obligation) of the plans is recognized on the balance sheet. Rather than recognize this amount in AOCI or as a rate base deferral account, the Company is requesting regulatory recognition and acknowledgement of a non-rate base deferral account to accumulate these amounts. Under current US GAAP, the amount in AOCI is recycled through the pension net benefit cost, similar to pre-changeover CGAAP, which is why the amount in AOCI is not requested to be included as a rate base account subject to amortization.

2012-13 RRA Request:

Under a US GAAP adoption scenario, FortisBC requests approval of a non-rate base deferral account in the amount of approximately $28.8 million in 2012 and $30.2 million in 2013. The adjustment essentially recognizes any unamortized gains and losses due to the application of the corridor approach, prior service costs (and credits), and any remaining unamortized transitional obligation. All of these components will be collected from customers in future periods when recognized through US GAAP periodic net benefit cost.

8. Financing Costs Under Effective Interest Method

Current Practice:

Pre-changeover CGAAP requires debt issue costs to be deferred and amortized using the effective interest method. The effective interest method is a method of calculating the amortized cost of a financial liability, including long-term debt instruments, and of allocating the interest expense over the term of the related debt instrument. The effective interest rate is the rate that exactly discounts estimated future cash payments through the expected life of the financial instrument. For regulatory purposes, the Company amortizes debt issue costs using the straight-line method. A non-rate base regulatory liability, previously approved by Commission Order G-184-10, is recorded to represent the cumulative difference between the two amortization methods.

US GAAP Guidance:

There is no explicit US GAAP literature that requires the use of the effective interest method for financial assets or financial liabilities. Although the effective interest method is a conceptually preferable method of interest income or expense recognition and would be accepted under US GAAP, it would be permissible to apply the straight line method of amortization for these financial instruments.

2012-13 RRA Update:

This item has been previously approved as a non-rate base deferral account pursuant to G-184-10, FortisBC has forecast a non-rate base regulatory liability in the amount of approximately $0.8 million in 2012 and $ $0.8 million in 2013 in order to continue to record amortized debt issue costs using the effective interest method for external financial reporting purposes. The non-rate base deferral account is expected to be refunded to customers over the maturity term of the outstanding debt through future rates.

9. Uncertain Tax Positions

Current Practice:

No similar standard exists under either pre-changeover CGAAP or IFRS.

US GAAP Guidance:

ASC 740-10-50-15, *Income Taxes - Disclosure*, otherwise known as Financial Accounting Standards Board Interpretation (FASB) No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes*, was implemented in 2006 and was intended to reduce uncertainty in accounting for income taxes. The standard requires a series of steps for the recognition, measurement, disclosure and presentation of uncertain tax positions. The accounting and reporting requirements of FIN 48 involve a two-step process that may result in a larger income tax liability due to the earlier recognition of income tax liabilities. The standard was implemented to reduce the uncertainty and diversity in practice that the FASB had observed which resulted in non-comparability across companies.

FIN 48 requires that FortisBC have documentation and support for each adjustment made to reconcile between accounting income and taxable income. The areas of documentation have included such items as the allowance for doubtful accounts, meals and entertainment expenses, unpaid compensation, inventory obsolescence, capitalized overheads, capital additions for tax purposes, dismantling costs and deferred charges. While there are many items to document and FortisBC is still at the documentation stage, the Company does not expect to have any material adjustments as a result of this standard. The documentation is still subject to audit and the audit may result in adjustments to positions and ultimately to the recognition of amounts under this standard.

2012-13 RRA Request:

Under a US GAAP adoption scenario, FortisBC requests approval of a non-rate base deferral account to capture any differences that arise from the implementation of FIN 48.

10. Embedded Derivatives in Power Purchase Agreements

Current Practice:

FortisBC entered into an agreement during 2010 to purchase fixed-price capacity during winter months through to February 2016. The contract is denominated in $USD. All costs associated with purchasing capacity in are recorded as power purchase expenses at the exchange amount. Under pre-changeover CGAAP, the $USD portion of the contract is not considered to be closely related to its host instrument and therefore bifurcation of a foreign exchange embedded derivative is necessary, which is required to be measured at the forward $USD value at each reporting date. The amount has been determined to be immaterial to date and therefore has not yet been recorded.

US GAAP Guidance:

ASC 815-15-25-1, *Derivatives and Hedging - Embedded Derivatives*, results in the same conclusion as above under pre-changeover CGAAP; therefore the relevant US GAAP guidance is generally consistent with pre-changeover CGAAP.

2012-13 RRA Request:

FortisBC requests approval of a non-rate base deferral account to capture the offset of any mark to market adjustment of the embedded foreign exchange derivative. The differences would be recovered from customers through future rates as the contract is settled at the $USD exchange amount.

Appendix F

Accounting Changes: International Financial Reporting Standards (IFRS)

INTRODUCTION

The purpose of this appendix is to identify the accounting policy changes required as a result of adopting IFRS for regulatory and external financial reporting in the absence of any other financial reporting alternative.

Part V of the Canadian Institute of Chartered Accountants Handbook – *Pre-Changeover Canadian Generally Accepted Accounting Principles* (CGAAP), is no longer available to FortisBC effective January 1, 2012 as it will be withdrawn by Canadian standard setters and will cease to exist as a financial reporting option. This leaves two available options; Generally Accepted Accounting Principles in the United States (US GAAP) or IFRS.

As outlined in Appendix E and the February 9, 2011 application submitted to the BCUC, the Company requested approval to adopt US GAAP effective January 1, 2012, for the calculation of cost of service, revenue requirements, rate base, and the preparation of regulatory schedules and filings. The Company will be adopting US GAAP for external reporting purposes effective January 1, 2012.

Should the adoption of US GAAP not be approved for regulatory reporting and FortisBC continued with the adoption of IFRS for both regulatory and external financial reporting purposes, there would be significant reconciling items expected as IFRS does not allow recognition of rate-regulated deferral accounting. The reconciliations are not only a result of derecognizing existing regulatory assets and liabilities, but also the periodic differences that would accumulate from the effects of rate regulation that are recognized differently for external financial reporting purposes. Over the course of a number of years, the reconciliation process would become increasingly complicated and the financial results for regulatory purposes would become increasingly different from the financial results for external financial reporting purposes.

Summary of Accounting and Other Policies

Accounting and other policies that FortisBC has been required to adopt under pre-changeover CGAAP would generally have been required under IFRS. In such cases where these accounting changes were not incorporated into customer rates, the regulatory asset or liability that is currently recorded to account for the timing difference would be derecognized under IFRS. The policies described in the following sections of this Appendix reiterate certain accounting treatments currently used under pre-changeover CGAAP, assesses whether these accounting treatments would also apply under an IFRS adoption scenario, and highlights any further accounting treatments that would be required as a result of adopting IFRS.

IFRS Non-Rate Base Deferrals

The current accounting treatment of the following items 1 through 7 is explained further in Appendix E. These items are also generally required under both pre-changeover CGAAP and US GAAP.

1. Deferred Income Tax

IFRS Requirement:

The measurement concept of the deferred income tax liability is not expected to differ materially under International Accounting Standard (IAS) 12, *Income Taxes.* However, the corresponding offset currently recorded as a non-rate base regulatory asset would be derecognized as a reduction to retained earnings in the Company's external financial statements. In addition, the change in the deferred income tax liability each year would be recognized in the period instead of deferred, resulting in an increase to income tax expense for external financial reporting purposes under IFRS.

2. Brilliant Terminal Station (BTS) Finance Lease

IFRS Requirement:

The substance of the BTS lease would continue to be classified as a finance (capital) lease under IAS 17, *Leases*. However, the non-rate base regulatory asset currently recorded to account for the timing differences of recording the BTS as a finance lease for external financial reporting and as an operating lease for regulatory reporting would be derecognized as a reduction to retained earnings in the Company's external financial statements. In addition, the timing difference experienced each year would be recognized in the period instead of deferred, resulting in an expected increase to interest expense and depreciation for external financial reporting purposes under IFRS.

3. Brilliant Power Purchase Agreement (BPPA) Finance Lease

IFRS Requirement:

The substance of the BPPA was determined to be an arrangement that contains a lease under International Financial Reporting Interpretations Committee (IFRIC) 4, *Determining Whether an*

Arrangement Contains a Lease and qualifies as a finance lease under IAS 17, *Leases*. The guidance is required to be applied on transition, where the effect on the Company's opening IFRS balance sheet as at January 1, 2011 is the recognition of an asset under finance lease with an offsetting obligation under finance lease for an equivalent amount. The nature of the lease arrangement would be classified as a finance lease because the present value of the minimum lease payments made by FortisBC represents the recovery of the entire amount of the initial investment in the Brilliant Plant by the owner over the term of the arrangement.

Each year subsequent to initial capitalization, the amount previously determined as power purchases under CGAAP will be replaced by depreciation on the finance lease asset and interest on the finance lease obligation. These amounts differ from the amount paid under the BPPA and is expected to increase interest expense and depreciation for external financial reporting purposes under IFRS.

4. Asset Retirement Obligation

IFRS Requirement:

IAS 37, Provisions, *Contingent Liabilities and Contingent Assets*, also requires recognition of all legal obligations associated with the retirement of tangible long lived assets as an ARO. The measurement requirements are generally the same as under CGAAP, and therefore the ARO related to the removal costs of Polychlorinated Biphenyls (PCBs) in station equipment and distribution equipment as determined under Environment Canada PCB Regulations would continue to exist. However, the non-rate base regulatory asset currently recorded that relates to the depreciation expense on the capitalized asset retirement cost and the accretion expense on the ARO liability that will be recognized between 2011 and 2025 would be derecognized as a reduction to retained earnings in the Company's external financial statements. In addition, the timing difference experienced each year would be recognized in the period instead of deferred, resulting in an expected increase in accretion expense and depreciation for external financial reporting purposes under IFRS.

In addition, IAS 37 expands the definition of an ARO to include constructive obligations. A constructive obligation is an obligation that derives from an entity's actions where by an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated to other parties that it will accept certain responsibilities and as a result, the entity has created a valid expectation that it will discharge that obligation.

FortisBC would not expect to record any further ARO liabilities under IFRS as a result of this guidance.

5. Trail Office Building Lease

IFRS Requirement:

IAS 17, *Leases*, also requires lease payments that are not made on a straight-line basis to be recognized in rental expense on a straight-line basis. Therefore, the Trail office lease stepped lease payments would continue to be levelized over the term of the lease. However, the non-rate base regulatory asset currently recorded to account for the timing differences of recording the Trail office lease expenses on a straight-line basis for external financial reporting and on the cash basis for regulatory reporting would be derecognized as a reduction to retained earnings in the Company's external financial statements. In addition, the difference between the lease payment and the lease expense recorded each year would be recognized in the period instead of deferred, resulting in an expected decrease to operating and maintenance expense for external financial reporting purposes under IFRS.

6. Financing Costs Under Effective Interest Method

IFRS Requirement:

IAS 32, *Financial Instruments - Recognition and Measurement*, also requires debt issue costs to be deferred and amortized using the effective interest method. However, the non-rate base regulatory liability currently recorded to represent the cumulative difference in amortization between the straight-line method for regulatory purposes and the effective interest method for external financial reporting purposes would be derecognized as an increase to retained earnings in the Company's external financial statements under IFRS. In addition, the difference between the two amortization methods recorded each year would be recognized in the period instead of deferred, which would result in a decrease to interest expense in the earlier portion of the long-term debt terms, for external financial reporting under IFRS.

7. Embedded Derivatives in Power Purchase Agreements

IFRS Requirement:

Under IAS 32, *Financial Instruments - Recognition and Measurement*, the $USD portion of the Company's fixed-price winter capacity purchase contract would also be considered not closely related to its host instrument. Therefore, bifurcation of a foreign exchange embedded derivative would be necessary, which is required to be measured at the forward $USD value at each reporting date. The amount has been determined to be immaterial to date and therefore has yet to be recorded. However, the offset of any mark to market adjustment of the embedded foreign exchange derivative that would likely be deferred as a non-rate base regulatory asset or liability for regulatory purposes would be recorded in net income for external financial reporting purposes under IFRS.

Other IFRS Differences

Differences between IFRS and pre-changeover CGAAP, other than those recognized in this Appendix, may be identified based on further detailed analysis by the Company, auditor interpretation, and other changes in IFRS subsequent to the 2012-2013 RRA.

Based on the requirements of IFRS as currently assessed, the Company has identified the following additional differences that would arise as a result of adopting IFRS. Should the Commission order the Company to adopt a modified version of IFRS with deferral accounting for regulatory purposes, the following changes would be required

1. Employee Future Benefits - Accrued Pension Costs

IFRS Requirement:

IAS 19, *Employee Benefits*, requires an entity to measure the present value of the defined benefit obligation for pensions at the balance sheet date of December 31, whereas FortisBC currently measures its employee future benefits as at September 30 under pre-changeover CGAAP. In addition, IFRS 1, First-time Adoption of IFRS, allows entities to recognize all cumulative unamortized actuarial gains and losses as part of the accrued pension, with an offsetting entry to retained earnings, if retrospectively recalculating amounts otherwise recognized under IFRS is not practicable, which is the case for FortisBC. In absence of any deferral accounting, the transition to IFRS would require FortisBC to recognize approximately $24.5 million increase to the accrued pension defined benefit obligation a reduction to retained earnings for external financial reporting purposes under IFRS. This estimate includes the assumption of a scenario where IFRS employee future benefits would permit the deferral of gains and losses for actuarial determinations.

An estimate of the forecast IFRS pension expense impact is discussed further in Tab 2, Section 2.0. Additionally, the adjustments required to pensions balances from pre-changeover CGAAP to IFRS are described in further detail in Tab 5, Section 5.4 for the "IFRS Prepaid (Accrued) Pension Costs" and "IFRS Pension Transitional Obligation Deferral Account".

8. Employee Future Benefits – Other Post-Employment Benefits (OPEB)

IFRS Requirement:

IAS 19, *Employee Benefits*, requires an entity to measure the present value of the OPEB obligation at the balance sheet date of December 31, whereas FortisBC currently measures its obligation at September 30. In addition, IFRS 1, First-time Adoption of IFRS, allows entities to recognize all cumulative unamortized actuarial gains and losses as part of the OPEB liability, with an offsetting entry to retained earnings, if retrospectively recalculating amounts otherwise recognized under IFRS is not practicable, which is the case for FortisBC. In absence of any deferral accounting, the transition to IFRS would require FortisBC to recognize approximately $8.9 million increase to the OPEB obligation and a reduction to retained earnings for external financial reporting purposes under IFRS. This estimate includes the assumption of a scenario where IFRS employee future benefits would permit the deferral of gains and losses for actuarial determinations.

An estimate of the forecast IFRS OPEB expense impact is discussed further in Tab 2, Section 2.0. Additionally, the adjustments required to OPEB balances from pre-changeover CGAAP to IFRS are described in further detail in Tab 5, Section 5.4 for the "IFRS Prepaid (Accrued) OPEB cost" and "IFRS OPEB Transitional Obligation Deferral Account".

9. Allowance for Funds Used During Construction

IFRS Requirement:

IAS 23, *Borrowing Costs*, allows capitalization of borrowing costs in a manner similar to how the Company currently capitalizes AFUDC. However, borrowing costs are defined as specifically excluding the cost of financing with equity. Therefore, to the extent any difference arises from the rate used for AFUDC and the rate weighted average cost of debt determined for IFRS, the difference would be recognized in interest expense for external financial reporting purposes under IFRS.

10. Investigative Spending

IFRS Requirement:

IAS 38, *Intangible Assets*, clearly distinguishes between research costs, which are expensed, and development costs, which are capitalized. Investigative spending, which are included as Preliminary and Investigative Charges within Deferred Charges in FortisBC's revenue requirements, include engineering and other costs associated with investigation of the scope and budget of capital projects. Depending on the nature of the costs included in Preliminary and Investigative Charges, certain of the amounts currently deferred could be expensed as research costs, resulting in an expected increase to operating and maintenance expenses for external financial reporting purposes under IFRS.

11. Capitalized Overhead

IFRS Requirement:

IAS 16, *Property, Plant and Equipment*, specifically lists administration and general overhead costs as a type of cost that would not be eligible for capitalization. As a result, FortisBC's currently approved rate of capitalized overhead may not meet the criteria of being directly attributable under IFRS. Any difference required to be recorded in the period would result in an expected increase to operating and maintenance expenses for external financial reporting purposes under IFRS.

12. Timing of Depreciation

IFRS Requirement:

IAS 16, *Property, Plant and Equipment*, specifically requires that the depreciation of assets commence when an asset is available for use. FortisBC currently records depreciation based on the annual opening balance as required under the BCUC Uniform System of Accounts. Incorporating the timing of asset additions into depreciation throughout the year would result in a higher depreciation expense for external financial reporting purposes under IFRS.

13. Gains and Losses on Disposal of Assets

IFRS Requirement:

IAS 16, *Property, Plant and Equipment*, specifically requires that gains and losses on disposal of assets be recognized immediately in income instead of the current regulatory practice of being charged to accumulated depreciation. Subsequent depreciation studies adjust future depreciation rates in the amount of the deferred gains or losses so that any gain or loss which is charged to accumulated depreciation will be reflected in future depreciation expense when it is refunded or collected in rates. Recording gains and losses immediately would result in volatility in the external financial reporting purposes under IFRS.

Prior Year Directive – Gains and Losses on Disposal

In accordance with the Commission's Prior Year Directive, as outlined in Commission Order G-184-10, the Company has identified any losses that are greater than $0.1 million and provided explanations for them below.

FortisBC does not forecast retirements, gains, or losses on disposal of property, plant and equipment. Therefore, the actual results for the full 2010 year and the first four months of 2011 have been summarized. Total losses, net of any gains, for each plant group is provided in the following table.

Table 1 Actual Losses on Retirement of Property, Plant and Equipment

	12 Months Ending December 31, 2010	4 Months Ending April 30, 2011
	($000s)	
Hydraulic Production Plant	210	-
Transmission Plant	2,842	-
Distribution Plant	1,329	103
General Plant	193	76
Plant in Service	4,574	179

Note: The Company does not forecast retirements, gains, or losses on disposal of property, plant & equipment.

There have been no individual retirements during 2011 that resulted in losses greater than $0.1 million. For the year ending December 31, 2010, all losses greater than $0.1 million have been summarized by vintage year (i.e. year of initial capitalization) for each asset class in the following table. The full and partial retirements (i.e. when part of a pooled asset is retired) are included with the amount of associated cost, amount of associated accumulated depreciation, and resulting loss. Explanations for the losses follow the table below.

Table 2 Actual Losses on Retirement of Property, Plant and Equipment

Vintage Year		12 Months Ending December 31, 2010 ($000s) Retired Cost	Retired Accum Depn	Loss
	Hydraulic Production Plant			
1982	Water Wheels, Turbines and Generators	256	140	116
2000	Accessory Electrical Equipment	302	173	128
		557	313	244
Vintage Year	**Transmission Plant**			
1987	Poles, Towers & Fixtures	302	188	114
2002	Poles, Towers & Fixtures	345	73	273
2005	Poles, Towers & Fixtures	553	83	470
1987	Conductors and Devices	311	143	168
1988	Conductors and Devices	193	85	108
2002	Conductors and Devices	345	73	273
2005	Conductors and Devices	553	83	470
		2,603	727	1,876
Vintage Year	**Distribution Plant**			
2000	Station Equipment	136	29	107
1980	Conductors and Devices	549	357	192
		685	386	299
	Plant in Service	3,846	1,426	2,420

Water Wheels, Turbines and Generators – This loss is from the retirement of generator and turbine components at the Corra Linn Dam. The components were retired in connection with the Corra Linn P4 Unit 1 Life Extension project, approved Commission Order G-147-06. The retirement was within the normal course of business. The loss occurred as a result of these components being removed from service prior to their expected life estimate. Subsequent depreciation studies will consider this retirement in the determination of future depreciation rates for this asset class.

Accessory Electrical Equipment – This loss is from the retirement of electrical components at the South Slocan Dam. The components were retired in connection with the approved South Slocan P3 Plant Completion project, approved Commission Order G-147-06. The retirement was within the normal course of business. The loss occurred as a result of these components being removed from service prior to their expected life estimate. Subsequent depreciation studies will consider this retirement in the determination of future depreciation rates for this asset class.

Poles, Towers, and Fixtures – These losses relate to the retirements of 9 and 10 Lines and 40 Line. The retirement of 9 & 10 Line was a result of the removal of a section of transmission poles between Grand Forks and Rock Creek, which was required in connection with the Kettle Valley project approved by Commission Order C-5-06. The retirement of 40 Line was a result of the removal of a section of transmission poles from RG Anderson Terminal Station to Vaseux Lake and from Vaseux Lake to Oliver. This retirement was required in connection with the Okanagan Transmission Reinforcement project approved by Commission Order G-5-08. The retirement was within the normal course of business. The loss occurred as a result of these components being removed from service prior to their expected life estimate. Subsequent depreciation studies will consider this retirement in the determination of future depreciation rates for this asset class.

<ins>Transmission Conductors and Devices</ins> – These losses relate to the same retirements of 9 and 10 Lines and 40 Line explained above for Poles, Towers, and Fixtures. The retirements were required in connection with the Kettle Valley project approved by Commission Order C-5-06, and the Okanagan Transmission Reinforcement project approved by Commission Order G-5-08. The retirement was within the normal course of business. The loss occurred as a result of these components being removed from service prior to their expected life estimate. Subsequent depreciation studies will consider this retirement in the determination of future depreciation rates for this asset class.

<ins>Station Equipment</ins> – This loss relates to the retirement of components of the South Slocan Distribution Station, which was performed in connection with the approved 30 Line Conversion project approved by Commission Order G-11-09. The retirement was within the normal course of business. The loss occurred as a result of these components being removed from service prior to their expected life estimate. Subsequent depreciation studies will consider this retirement in the determination of future depreciation rates for this asset class.

<ins>Distribution Conductors and Devices</ins> – This loss relates to the retirement of distribution conductors and devices, which are required to rehabilitate, rebuild or upgrade distribution lines in order to ensure reliable customer service and employee and public safety. These distribution sustainment projects are approved as part of the annual capital expenditure plans. The retirement was within the normal course of business. The loss occurred as a result of these components being removed from service prior to their expected life estimate. Subsequent depreciation studies will consider this retirement in the determination of future depreciation rates for this asset class.

Prior Year Directive - Major Inspections

In accordance with the Commission's Prior Year Directive, as outlined in Commission Order G-184-10, FortisBC's description of the accounting and depreciation treatment of Major Inspection costs follows.

IAS 16, *Property, Plant and Equipment*, recognizes that a condition of continuing to operate an item of property, plant and equipment may be performing regular major inspections regardless of whether parts of the item are replaced.

Pre-changeover CGAAP and US GAAP do not contain explicit guidance for major inspections like IFRS does. However, what would normally be classified as a major inspection under IAS 16 would generally be expected to meet the definition of an asset under both pre-changeover CGAAP and US GAAP.

Major inspections, in the context of FortisBC's business, are most similar to what is broadly classified as "Transmission Line Condition Assessments", "Station Condition Assessments", and "Distribution Line Condition Assessments" in FortisBC's Capital Expenditure Plan submissions. As outlined in FortisBC's response to Directive 16 from Commission Order G-195-10, which has been filed as Appendix M in this 2012-13 RRA, the costs involved in these assessment programs are eligible capital expenditures under both pre-changeover CGAAP and US GAAP. This is because a managed, scheduled preventative maintenance program for identifying faults in electrical infrastructure would provide economic benefits over the course of more than one year.

The fundamental difference between accounting for major inspections under IAS 16 and how condition assessments are currently accounted for by FortisBC is the approach to depreciation. IAS 16 explicitly requires major inspections to be depreciated separately over the term of the inspection period such that the cost of the inspection is fully depreciated before the next inspection of the same asset begins, which would be an eight-year cycle for transmission and distribution assessments and a ten-year cycle for stations at FortisBC. The shorter life cycle for depreciation would result in an increase in depreciation expense under IFRS.

Under pre-changeover CGAAP and US GAAP, these assessments are capitalized to the assets themselves and depreciated together over the appropriate life estimate, which would be approximately thirty years. While the capitalization of major inspection type items may be consistent among the various accounting standards, as discussed in Tab 2, Section 2.0, FortisBC is not intending to adopt IFRS at this time, therefore the major inspection depreciation requirements of IAS 16 have not been applied to this 2012-13 RRA.

Appendix G

FORTISBC OPERATING STATISTICS

	2006		2007		2008		2009		2010		2011	
	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Direct Customer Count												
Residential	88,438	89,181	93,515	93,647	95,504	95,502	96,866	96,565	97,956	97,883	99,663	99,457
Commercial (Commercial/Industrial/Wholesale)	10,375	10,330	11,163	11,055	11,393	11,259	11,385	11,348	11,482	11,462	11,756	11,615
Lighting & Irrigation	2,816	2,902	3,227	3,022	3,031	2,958	2,939	2,940	2,917	2,905	2,917	2,905
Average Number of Customers	100,687	100,996	103,022	104,360		107,040	110,921	108,946	112,051	110,598	113,346	112,288
Indirect Customers		49,762		46,334		47,809		48,444		48,769		
Energy Sold (GWh)												
Residential	1,080	1,091	1,155	1,160	1,212	1,221	1,265	1,293	1,210	1,224	1,261	1,301
Residential Use per Customer (MWh)		11.92		12.71		12.94		13.25		12.60		12.77
Commercial (Commercial/Industrial/Wholesale)	1,893	1,890	1,877	1,869	1,790	1,811	1,794	1,799	1,812	1,769	1,844	1,827
Lighting & Irrigation	58	59	64	62	62	55	70	65	56	53	57	57
Total Energy Sold	3,031	3,040	3,096	3,090	3,064	3,087	3,129	3,157	3,078	3,046	3,162	3,187
Headcount												
Average Full Time Equivalent Employees		496		532		545		540		534		
Total Employees		563		557		559		554		549		
Transmission and Distribution												
Total Distribution Assets/Network (km)		6,471		6,866		6,979		6,953		6,995		
Distribution Lines (km)		5,063		5,458		5,539		5,560		5,605		
Transmission Lines (km)		1,408		1,408		1440		1,393		1,390		
Total Substations		64		64		64		66		64		
System Losses (%) - Gross Load		10.7		9.4		9.2		9.2		8.4		8.8
Generation												
Energy Produced (GWh)		1,509		1,498		1,610		1,586		1,530		
Generating Capacity (MW)		235		223		223		223		223		
Peak Demand (MW) - Summer	494	554	530	569	567	537	557	561	560	554	578	560
Peak Demand (MW) - Winter	708	718	708	683	720	746	697	714	698	707	723	710
Total Power Purchases ($000s)	65,067	67,576	69,260	66,629	68,538	66,010	70,944	70,776	80,408	71,964	81,212	75,956
Total DSM Energy Saved (GWh)	20.4	23.1	21.8	27.9	19.5	27.3	25.3	28.4	27.5		39.7	

Appendix H

FORTISBC MOODY'S CREDIT OPINION 2010

MOODY'S
INVESTORS SERVICE

Credit Opinion: FortisBC Inc

Global Credit Research - 06 May 2010

British Columbia, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	Baa1

Contacts

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Key Indicators

[1]**FortisBC Inc**

	2009	2008	2007	2006	2005
(CFO Pre-W/C + Interest) / Interest Expense	2.9x	2.7x	2.8x	2.8x	2.5x
(CFO Pre-W/C) / Debt	11.9%	11.2%	10.9%	11.5%	8.9%
(CFO Pre-W/C - Dividends) / Debt	9.6%	8.9%	8.8%	9.4%	7.2%
Debt / Book Capitalization	59.4%	63.8%	64.4%	65.1%	67.5%

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk utility operating in a supportive regulatory environment

Relatively weak quantitative credit metrics are expected to improve modestly

Growth in rate base and cash flow expected to result in smaller free cash flow deficits

Improved credit facilities result in a satisfactory liquidity position

Corporate Profile

Headquartered in Kelowna, British Columbia, FortisBC Inc. (FBC) is a vertically integrated regulated hydro-electric utility that operates primarily under a cost-of-service regulatory regime. FBC is an indirect, wholly-owned subsidiary of Fortis Inc. (FTS, unrated), a diversified electric and gas utility holding company based in St. John's, Newfoundland.

SUMMARY RATING RATIONALE

The Baa1 senior unsecured rating of FBC reflects the low-risk nature of the utility where over 95% of its operations are regulated and the few unregulated operations it does have are viewed to be relatively low-risk. The rating also considers FBC's location in a supportive regulatory environment with a limited performance based regulatory regime that has allowed FBC to consistently earn more than its allowed return on equity (ROE) since 2003. These strengths are offset by quantitative credit metrics that remain weak relative to those of peers, despite a gradual improvement in recent years. Over the past five years, FBC's investment program has resulted in a 70% increase in rate base assets and steady growth in cash flow from operations. FBC's capital spending will remain elevated in the medium term as the company continues to invest to strengthen its existing system and accommodate relatively strong growth within its service territory but the planned spending is more manageable in the context of its current rate base and cash flow. The increase in FBC's allowed ROE to 9.9% for 2010 is expected to modestly improve metrics in 2010 and beyond. We expect credit metrics to show further modest improvement as FBC's cash flow continues to grow due to both historic and forecast capital spending. Higher cash flow from FBC's larger rate base should result in smaller free cash flow deficits going forward. In our view, FBC's liquidity resources are sufficient given the changes to its credit agreement announced in April 2010.

DETAILED RATING CONSIDERATIONS

PREDOMINANTLY REGULATED UTILITY OPERATING IN A SUPPORTIVE REGULATORY ENVIRONMENT

FBC's rating reflects the company's low business risk profile where over 95% of its operations are regulated and its unregulated operations are limited and low-risk in nature. FBC's primary unregulated activity is the sale of electricity from the Walden Power hydro-electric independent power project (IPP) under a long-term power purchase agreement (PPA) with British Columbia Hydro & Power Authority (BCH; Aaa, stable). With the exception of BCH, FBC is the only integrated, regulated electric utility operating in the province of British Columbia.

Moody's considers FBC's business risk to be lower than that of other cost-of-service regulated vertically integrated utilities. While vertically integrated utilities are often exposed to commodity price and volume risks in their generation segments (fuel purchase and electricity sales), a hydro-electric utility's greatest risk is hydrology. Actual water flows can vary significantly from those forecast with significant cash flow repercussions. However, FBC's hydrology risk is substantially mitigated by the Canal Plant Agreement (CPA), which runs until at least 2035. Under the CPA, FBC and others cede scheduling control of their generation facilities to BCH in exchange for power from BCH based on 50-year historical hydrology regardless of the actual hydrological conditions in any contract year. The hydro-electric generation facilities owned by FBC provide about 45% of its annual energy requirement. The PPAs with BCH and Brilliant Power Corporation (BPC, A1, stable) provide the bulk of the balance of FBC's requirements, representing approximately 24% and 26% respectively of its annual energy requirements.

FBC's location in British Columbia, which, until recently, enjoyed a relatively strong provincial economy and continues to enjoy a supportive regulatory climate, contributes to our view of FBC as a lower risk utility. We consider Canada to have supportive regulatory and business environments relative to other jurisdictions globally. Furthermore, the regulatory environment in British Columbia is considered one of the more supportive in Canada reflecting the fact that regulatory proceedings tend to be less adversarial and decisions tend to be balanced with minimal regulatory lag. The progress of FBC's 2010 Revenue Requirements Application demonstrated these characteristics of the regulatory environment clearly. The application was approved within three months of initial submission as a result of a negotiated settlement agreement (one of several negotiated settlements that have been achieved since FTS acquired ownership of FBC in 2004). The approved rate increase of 3.5% was relatively close to FBC's updated request of 4%. In December 2009, the British Columbia Utilities Commission's (BCUC) ROE and cost of capital decision resulted in an increase in FBC's ROE from 8.87% in 2009 to 9.9% for 2010. Importantly, the previously approved rate increase was revised to 6% on December 30, 2009 to reflect the impact of this decision, meaning that FBC did not experience any delay in benefiting from the improvement in ROE. One other outcome of the ROE and cost of capital decision was the elimination of the automatic adjustment mechanism that had previously been used to update the allowed ROE. We see this as positive since the adjustment mechanism had been distorted by the compression of Government of Canada Bond yields during the credit crisis and produced lower allowed ROEs whilst corporate risk premiums increased significantly. The BCUC will consider alternative adjustment mechanisms in the next twelve months.

FBC is regulated primarily on a cost of service basis although there are limited performance based rate-making (PBR) provisions in place relative to operating and maintenance (O&M) expenses. To a degree, the regulatory regime mitigates FBC's exposure to forecast risk by allowing the company to forecast costs other than O&M in its annual revenue requirements application and then recover or refund variations between certain forecast and actual revenues and expenses. Under the PBR agreement, FBC has been able to achieve actual ROEs in excess of its allowed ROEs since 2003.

FBC's largest expense item is purchased power; however, certainty of recovery of these costs is high because the majority of FBC's power purchases occur pursuant to the BPC and BCH PPAs, both of which have been approved by the BCUC. The costs incurred by FBC under these agreements are therefore, effectively a flow-through to ratepayers.

On a periodic basis, FBC submits a capital plan to the BCUC for review and approval. The capital plan and its rate impacts are also reviewed annually during FBC's revenue requirement application. This process of regulatory pre-approval of capital spending reduces the risk of being unable to fully recover capital investments that have already been incurred.

RELATIVELY WEAK FINANCIAL METRICS COMPARED TO PEERS

FBC's credit metrics have demonstrated some improvement since the company was acquired by FTS in 2004. We expect FBC's financial metrics to gradually exhibit further modest improvement over the next few years, reflecting the higher allowed ROE and the growth in rate base, resulting in ratios of CFO pre-W/C to Debt in the range of 13% and Interest Coverage of approximately 3.1x by 2011. Achievement of these metrics is dependent upon, among other things, execution of BCUC-approved capital spending on budget and effective management of forecast risk.

Despite the actual and anticipated improvement in FBC's metrics, the company's ratios remain weak relative to peers. However, we believe that FBC's relatively weak financial profile is offset by the company's location in a supportive regulatory environment.

FBC's ratios are generally consistent with those of Baa3 electric utilities, and remain weaker than its Baa1-rated sister companies, FortisAlberta Inc. (FAB, a distribution utility) and Newfoundland Power Inc. (NPI, predominantly a T&D utility). For example, FAB and NPI have reported CFO pre-W/C to Debt of approximately 14%-15% while FBC's range has been in the low teens. The marked improvement in FBC's adjusted Debt / Book Capitalization to 59.4% at December 31, 2009 compared to 63.8% at December 31, 2008 reflects the change in Canadian accounting standards, effective January 2009, requiring regulated utilities to recognize future income tax assets and liabilities as well as related regulatory liabilities and assets. This has a ratio impact because deferred taxes are a component in the calculation of capitalization. Moody's notes that the improvement is due to a non-cash accounting change that does not alter FBC's fundamental credit profile although it does enhance the comparability of debt/capitalization metrics between Canadian and US-based peers. Given the relatively small 7.5% weighting of the debt to capitalization metric in the rating methodology, the accounting change does not materially impact the methodology-indicated rating.

CAPITAL EXPENDITURES EXPECTED TO MODERATE RELATIVE TO CASH FLOW

To date, FBC has managed a large capital expenditure program successfully, and regular equity contributions from FTS have enabled it to maintain its deemed 60/40 capital structure. The size of FBC's capital program reflects growth in portions of its service territory as well as the continued need to reinforce FBC's system following a period of under-investment by the previous owner. Between 2005 and 2007, FBC's capex typically represented around 2x its CFO pre-W/C, resulting in relatively large free cash flow deficits. Capital expenditures will remain high in 2010, but are expected to moderate and average roughly 1.2 times CFO pre-W/C over the next five years. We expect that FBC will continue to generate negative free cash flow in the medium-term, but from 2011 these deficits are likely to be at lower levels than in the recent past.

There is a risk that continued elevated capital expenditures, which are expected to necessitate rate increases above the level of inflation, could lead to ratepayer fatigue. However, this risk should be significantly mitigated by the BCUC's review and approval of FBC's periodic capital plans and its annual review of the company's spending plans as part of the annual revenue requirements application process. Once the capital spending plans are approved by the BCUC, we believe that it is relatively unlikely that the BCUC would then fail to approve rate increases sufficient to support those capital expenditures. We also note that the increase in FBC's rates is consistent with trends across the Province, and in fact FBC's approved rate increase of 6% for 2010 is lower than the 9.26% increase requested by BCH for its service territory. Accordingly, we believe that the greatest risk related to FBC's capital expenditure plans is the company's ability to prudently manage its projects to avoid excessive cost overruns, the full recovery of which might not be permitted by the regulator.

Liquidity Profile

FBC's liquidity arrangements are satisfactory. We estimate that FBC will have negative free cash flow of approximately $90 million for the twelve month period to June 30, 2011. The company does not have material debt maturities in this period. With undrawn committed credit facilities of approximately $118 million at March 31, 2010, FBC is able to withstand our standard liquidity stress scenario, which assumes that an issuer loses access to new capital, other than credit available under its committed credit facilities, for a period of 12 months. On this basis, FBC has an estimated buffer of approximately $30 million, not including projected equity contributions from FTS.

On April 30, 2010, FBC announced that it had received all approvals required to amend the terms of its credit facility.

Once amended three-year revolving tranche to will be increased to $100 million with a May 8, 2013 maturity and the 364-day revolving tranche will be reduced to $50 million with a May 5, 2011 maturity. The three-year tranche will continue to be extendible annually for further one-year periods, subject to the agreement of the banks, while the 364-day tranche will continue to have an automatic 6-month term-out in the event that it is not extended.

We consider FBC's access to the financial resources and executive support of its parent, FTS, to be a credit strength. Regardless of the fact that FBC is insulated to a degree from the credit profile of its parent by certain covenants in its credit agreement, FTS has nonetheless consistently demonstrated good management and support of its subsidiaries and the ability to maintain or rebuild good relationships with regulators. While FTS could seek to increase dividends from FBC to support the operations of the parent or sister subsidiaries, the expectation is that dividends will not exceed the level necessary to maintain FBC's 60/40 target capital structure. FTS' liquidity is supported by a $600 million committed syndicated credit facility, maturing in May 2012, which had $547 million of availability at March 31, 2010. We also expect that FTS will continue to contribute capital as needed in order to allow FBC to remain close to its deemed capital structure.

Rating Outlook

The rating outlook is stable based on our expectation that FBC will continue to achieve rate increases necessary to support its capital spending program or, in the absence of such rate increases, that FBC will restrict the scope and scale of its capital program to ensure that its credit metrics are not materially weakened.

What Could Change the Rating - Up

FBC's rating could be positively impacted if FBC were to be able to demonstrate a sustainable improvement in financial ratios, such as CFO pre-W/C Interest Coverage of approximately of 4.0 times and CFO pre-W/C to Debt above 16%.

What Could Change the Rating - Down

A downgrade of FBC's rating would likely require a combination of a deterioration of FBC's regulatory framework, ability to earn its allowed return, liquidity and financial profile. This might include sustained weakening of FBC's metrics such as CFO pre-W/C Interest coverage of below 2.7x and CFO pre-W/C to Debt below 10%.

Rating Factors

FortisBC Inc

Regulated Electric and Gas Utilities Rating Methodology	Aaa	Aa	A	Baa	Ba	B
Factor 1: Regulatory Framework (25%)			X			
Factor 2: Ability to Recover Costs and Earn Returns (25%)			X			
Factor 3: Diversification (10%)						
a) Market Position (5%)				X		
b) Generation and Fuel Diversity (5%)		X				
Factor 4: Financial Strength, Liquidity & Financial Metrics (40%)						
a) Liquidity (10%)				X		
b) CFO pre-WC + Interest / Interest (7.5%)				X		
c) CFO pre-WC / Debt (7.5%)					X	
d) CFO pre-WC - Dividends / Debt (7.5%)				X		
e) Debt / Capitalization or Debt / RAV (7.5%)					X	
Rating:						
a) Methodology Implied Senior Unsecured Rating				**Baa1**		
b) Actual Senior Unsecured Rating				**Baa1**		

Appendix I

FORTISBC DBRS CREDIT OPINION 2010

Rating Report
Report Date:
October 26, 2010
Report Date:
June 5, 2009

FortisBC Inc.

Insight beyond the rating.

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The Company
FortisBC is a vertically integrated utility company operating in south-central British Columbia (B.C.). Its generation assets include four hydroelectric generating plants (totalling 223 MW) on the Kootenay River in south-central B.C. and the Company provides electricity services to approximately 160,000 customers. FortisBC is ultimately a wholly owned subsidiary of Fortis Inc., a diversified, international utility holding company having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

Recent Actions
October 1, 2010
Upgraded

Rating

Debt	Rating	Rating Action	Trend
Secured Debentures	A (low)	Upgraded	Stable
Unsecured Debentures	A (low)	Upgraded	Stable

Rating Rationale

On October 1, 2010, DBRS upgraded the ratings of FortisBC Inc.'s (FortisBC or the Company) Secured and Unsecured Debentures to A (low) from at BBB (high). The trends on both ratings are maintained at Stable. Rather than by one defining event, the upgrade was driven by a number of factors, including: 1) the Company is well through its large capital expenditure program, which has been ongoing for several years, and has demonstrated an ability to execute as planned; 2) FortisBC has maintained stable credit metrics over the past five years, despite the continued capital expenditure-driven free cash flow deficits; 3) a continued supportive regulatory environment; 4) the Company's increased size and scale; and 5) strong parental support from Fortis Inc. over the years, as demonstrated by consistent equity injections to maintain FortisBC's financial profile.

As FortisBC has successfully invested considerable capital (increasing total assets by approximately 65% since 2005) and continues to invest sums considerably in excess of cash flow levels, the Company's credit metrics have nonetheless remained extremely resilient. This can be attributed largely to the fact that most expenditures have been concentrated in the distribution business, where invested capital generally enters rate base (and earnings begin) reasonably quickly. The primary focus of the capital program is for the expansion and improvement of FortisBC's transmission and distribution systems in order to meet demand growth and achieve increased reliability. The elevated capital expenditures may approach $650 million (net of customer contributions) over the next five years, resulting in free cash flow deficits that will continue to be funded with a combination of incremental debt financing and equity support from parent company Fortis Inc. to maintain its capital structure at the regulatory-approved levels. Fortis Inc. has in the past regularly invested incremental equity in FortisBC as needed. (Continued on page 2.)

Rating Considerations

Strengths
(1) Supportive regulatory environment
(2) Low-cost, competitive hydroelectric generation base
(3) Secure, reasonably priced electricity supply contracts
(4) Diversified customer base

Challenges
(1) Large capital expenditure program
(2) Free cash flow deficits over the medium term
(3) Earnings and cash flow affected by lower ROEs

Financial Information

	12 mos. Ending	For the 12-month period ended				
($ millions)	June 30, 2010	Dec. 2009	Dec. 2008	Dec. 2007	Dec. 2006	Dec. 2005
EBIT	74.2	73.0	67.3	62.7	57.2	51.5
EBIT interest coverage	2.03	2.04	2.05	2.04	2.11	2.20
EBITDA interest coverage	3.09	3.06	3.09	3.04	3.09	3.00
% total debt in the capital structure	60.4%	60.4%	60.4%	61.1%	60.9%	61.9%
Cash flow/total debt	12.4%	12.2%	11.4%	11.4%	11.2%	10.1%
Cash flow/capital expenditures (times)	0.60	0.69	0.62	0.45	0.53	0.40
Free cash flow	(55.6)	(55.3)	(45.6)	(73.3)	(67.4)	(80.1)
Approved ROE	9.90%	8.87%	9.02%	8.77%	9.20%	9.43%

FortisBC Inc.

Report Date:
October 26, 2010

Rating Rationale (Continued from page 1.)

DBRS notes that it has also resolved the Positive trend assigned to Fortis Inc.'s Unsecured Debentures and Preferred Shares, upgrading the ratings to A (low) and Pfd-2 (low), respectively, and changing its trends to Stable (see October 1, 2010 press release).

The regulatory environment remains stable and supportive, providing a strong cost-of-service/rate-of-return rate-setting methodology with some performance-based rate (PBR) setting attributes. The cost-of-service framework allows for full recovery of all forecast and prudently incurred power purchase costs, operating expenses and capital expenditures within a reasonable time frame. The British Columbia Utilities Commission (BCUC) approved a settlement agreement pertaining to the Company's 2010 rates, which incorporated the expected increase in FortisBC's return on equity (ROE) to 9.90%, up from 8.87% in 2009. The ROE increase stemmed from a positive 2009 decision which also determined that the automatic adjustment mechanism that was used to determine the ROE on an annual basis will no longer apply, and the ROE as determined will apply until changed by the BCUC. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. While the increase in ROE is positive, there does remain uncertainty as to when and how ROE levels will be adjusted in the future.

The capital expenditure program has resulted in the Company exhibiting growth that is considered strong for a regulated utility, with the rate base growing at approximately 10% per year over the past five years. The Company's increased size, with total assets of approximately $1.2 billion, should provide it with improved economies of scale, operating efficiencies and access to capital. While DBRS had in the past viewed FortisBC's size as a negative factor, this is no longer a material issue given its now-larger presence.

DBRS expects key credit metrics to improve modestly over the coming years as a result of the recent favourable regulatory decisions, as capital assets are added to rate base, and as capital expenditures level off.

Rating Considerations Details

Strengths

(1) FortisBC operates in a stable, supportive regulatory environment that allows it to recover its cost of service and earn a return on its investments. The Company has operated under a PBR mechanism, in one capacity or another, since 1996, providing it with incentives for achieving productivity improvements.

(2) FortisBC owns and operates four low-cost hydroelectric generating plants on the Kootenay River system, with a total generating capacity of 223 megawatts (MW), which provide about 45% of energy and 30% of FortisBC's capacity needs. The Company is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, in which BC Hydro takes all of the power actually generated by the plants and is contractually obligated to deliver a fixed amount of power to the Company, which is currently based on 50-year historical water flows. This provides stability to a significant portion of the Company's earnings and cash flows, removing from this portfolio the water flow risk that is experienced by other hydro-based utilities. Furthermore, FortisBC retains its right to the original water licenses and flows in perpetuity.

(3) FortisBC also benefits from having secure, reasonably priced electricity supply contracts including: (a) a long-term "take or pay" contract with Brilliant Power Corporation (Brilliant, rated A (high) with a Stable trend; see separate DBRS rating report dated September 16, 2009). The contract runs until 2056 and supplies low-cost power representing close to 28% of the Company's energy needs; and (b) a power purchase contract with the government-owned British Columbia Hydro & Power Authority (BC Hydro, rated AA (high), with a Stable trend; see separate DBRS rating report dated December 1, 2009). This contract has flexible volumes (based on rolling five-year nominations of capacity requirements) and expires in 2013. The parties are currently in the process of negotiating renewal of the contract. As it currently stands, approximately 95% of FortisBC's energy requirements are met through the combination of owned generation and these supply sources. However, approximately 80% of its peak capacity requirements are met through these same resources. The balance of supply is met through small power purchase contracts and spot market purchases.

FortisBC Inc.

Report Date:
October 26, 2010

Prudently forecast and incurred costs related to these small power purchase contracts and spot market purchases (which account for approximately 5% of the Company's energy load requirements) are passed through to customers as well. The Company has made various types of advance purchases, including capacity purchases, call options and fixed-price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

(4) The Company has a diverse customer base in a growth-oriented franchise area, which provides a degree of stability to revenues and earnings. For 2009, electricity sales to stable residential customers accounted for about 41% of total sales volume, while 23% of sales were to commercial customers and 30% to wholesale customers (which, in turn, sell primarily to residential and commercial customers). Only 6% of sales were to low-margin, economically sensitive industrial customers. FortisBC's level of diversification and low reliance on economically sensitive customers helps mitigate the potential negative impacts of an economic downturn.

Challenges

(1) FortisBC's financial profile continues to be affected by free cash flow deficits due to the ongoing large capital expenditure program; however, credit metrics remain acceptable for the current rating. The Company's capital expenditure program has been ongoing for several years and is expected to be approximately $650 million (net of customer contributions) in projects over the next five years. Over the next few years, internal cash flow generation (net of dividends) will continue to fund the majority of capital expenditures. The remainder will be financed with a combination of incremental debt and equity support from Fortis, with the target of maintaining a capital structure at the regulatory-approved 60%/40%. The Company will need to seek some external debt financing during this stage of capital growth, which will likely keep key coverage ratios relatively flat during this period. Fortis is expected to provide equity support as needed in order to maintain the Company's regulatory-approved capital structure.

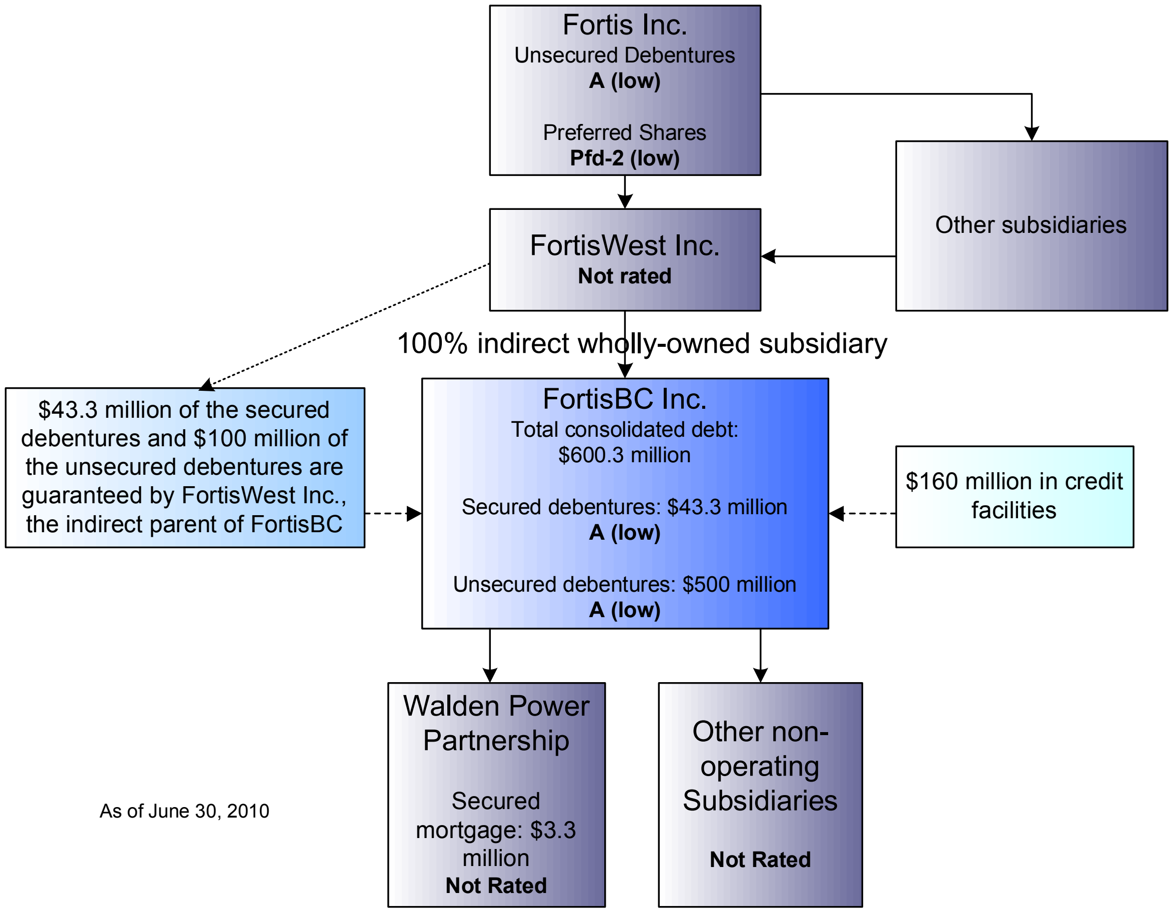
(2) The Company faces execution risk with regard to its large capital expenditure program over the next five years. The focus will be on improving the strength and reliability of the transmission and distribution system – in view of the strong growth in FortisBC's service territory – and also on completing projects on budget. However, it should be noted that the Company is already a number of years into the current capital expenditure program, with many projects already complete.

(3) Although the BCUC terminated the automatic adjustment ROE formula and set FortisBC's approved level at 9.9% (effective January 1, 2010), it had been in the low 9% and below since 2007. While FortisBCs ROE is now set at a benchmark level plus 40 basis points (bps), the absolute increase in the benchmark level (being Terasen Gas Inc.'s (TGI) ROE, which rose to 9.50%) drove the increase in FortisBC's to the 9.9% level. With the use of the automatic adjustment formula having been terminated, there is uncertainty as to how ROE levels will be determined in the medium and longer term; the BCUC has directed TGI to investigate alternative mechanisms.

FortisBC Inc.

Report Date:
October 26, 2010

Simplified Ownership/Debt Chart



FortisBC Inc.

Report Date:
October 26, 2010

Earnings and Outlook

($ millions)	12 mos. Ending June 30, 2010	For the 12-month period ended Dec. 2009	Dec. 2008	Dec. 2007	Dec. 2006
Revenues	246.7	244.1	229.2	219.7	207.6
EBITDA	113.5	110.1	101.5	93.8	84.1
EBIT	74.2	73.0	67.3	62.7	57.2
Gross interest expense	36.4	35.4	32.4	30.4	26.7
Core net income	37.1	36.2	32.7	30.1	26.5
Net income (reported)	37.1	36.2	32.7	30.1	26.5
Return on average common equity	9.2%	9.5%	9.4%	9.6%	9.5%
Rate Base	949.0	867.7	822.8	747.2	676.0
Growth in Rate Base	15.3%	5.5%	10.1%	10.5%	14.3%
Deemed common equity	40.0%	40.0%	40.0%	40.0%	40.0%
Approved ROE	9.90%	8.87%	9.02%	8.77%	9.20%

Summary

FortisBC has historically demonstrated strong and stable growth in EBITDA and EBIT, reflective of its expanding customer base and rate base. FortisBC's operations are almost 100% regulated, providing strong stability to earnings and cash flows. Earnings stability is further bolstered by the favourable customer mix, with residential and commercial customers providing the majority of the Company's margin.

Electricity revenues increased for the 12 months ending June 30, 2010, as a direct result of rate increases approved by the BCUC, as well as an increase in electricity sales throughout the period. Sales increased as a result of favourable growth in the majority of the Company's customer classes.

The increase in interest expense for the 12 months ending June 30, 2010, and year ending 2009, is primarily due to increased borrowings sourced to finance the large capital expenditure program, although this increase was partially offset by lower interest rates on bank credit facilities. Nonetheless, coverage ratios remain fairly stable due to earnings growth.

The impact of power price volatility on earnings is limited, as power procurement-related costs are passed on to customers. Costs stemming from owned generation and the long-term power purchase agreements (PPAs) that supply approximately 95% of FortisBC's power load requirements are automatically passed through to customers. The remaining 5% is procured through spot market purchases and small independent power purchase contracts. Prudently forecast and incurred costs related to these spot market purchases are passed through to customers as well. The Company has made various types of advance market purchases, including capacity purchases and fixed-price energy purchases, to help mitigate the risks of market volatility and availability on its spot market purchases.

Outlook

DBRS expects EBIT and net income to continue to grow over the medium term, driven by addition of capital assets as well as the increase in rate base and ROE to 9.90% for both 2010 and 2011. The investment in capital assets is necessary to ensure dependable service to a growing customer base, as well as public and employee safety with an upgraded system.

Key credit metrics are expected to increase over the coming years as capital expenditures level off and earnings and cash flows benefit from higher rates, an increased rate base and ROE.

FortisBC Inc.

Report Date:
October 26, 2010

Financial Profile

($ millions)	12 mos. Ending	For the 12-month period ended			
Cash Flow Statement	June 30, 2010	Dec. 2009	Dec. 2008	Dec. 2007	Dec. 2006
Core net income	37.1	36.2	32.7	30.1	26.5
Depreciation and amortization	39.7	37.5	34.2	31.1	26.9
Other non-cash adjustments	1.7	2.0	(1.8)	(0.1)	(0.1)
Cash Flow From Operations	78.6	75.7	65.1	61.0	53.3
Common dividends	(14.5)	(14.5)	(13.4)	(11.8)	(10.2)
Capital expenditures	(130.2)	(110.2)	(105.3)	(134.2)	(101.1)
Free Cash Flow Before W/C Changes	(66.1)	(49.0)	(53.6)	(85.0)	(58.0)
Net changes in working capital	10.5	(6.3)	8.1	11.7	(9.4)
Net Free Cash Flow	(55.6)	(55.3)	(45.6)	(73.3)	(67.4)
Other investing activities	4.6	(2.8)	(2.2)	(0.1)	(2.8)
Other adjustments	(0.6)	(0.6)	0.3	(0.6)	2.8
Amount to be Financed	(51.7)	(58.7)	(47.4)	(74.0)	(67.4)
Net debt financing	2.1	49.7	32.5	60.2	40.9
Net equity financing	10.0	10.0	15.0	15.0	20.0
Other financing	0.0	(1.0)	(0.0)	(1.2)	0.0
Net Change in Cash	(39.5)	(0.0)	0.0	(0.0)	(6.5)
% debt in capital structure	60.4%	60.4%	60.4%	61.1%	60.9%
EBIT interest coverage (times)	2.03	2.04	2.05	2.04	2.11
Cash flow/total debt	12.4%	12.2%	11.4%	11.4%	11.2%
Total debt to EBITDA (times)	5.59	5.64	5.60	5.69	5.67
Dividend payout ratio	39.0%	40.0%	41.0%	39.3%	38.5%

Summary

FortisBC's cash flow from operations has historically displayed underlying stability and growth due to both earnings and investment in plants. The increase in depreciation expense in recent years can be attributed to a growing depreciable asset base as capital assets are added to rate base.

Cash flow from operations has risen on account of increases in cash provided by net earnings and depreciation.

Although FortisBC maintains strong and increasing cash flow from operations, elevated capital expenditure levels continue to cause free cash flow deficits, which are financed with a combination of incremental debt and equity from Fortis, with the target of maintaining capital structure at the regulatory-approved 60%/40%. DBRS notes that the Company's deficits have been declining as capital assets are added to rate base free cash flow.

Overall, the Company has maintained a favourable financial profile, reflecting a solid and stable balance sheet and credit metrics.

Outlook

The Company will continue to generate free cash flow deficits over the medium term as it invests in the improvement of its transmission and distribution systems in order to meet the growth in its service territory. Annual capital expenditures are expected to remain high, with approximately $650 million in projects planned over the next five years. Annual average capital expenditures are expected to create financing requirements, after dividends, in the $40 million to $100 million range per year, which DBRS expects will be financed with incremental debt and equity from Fortis. Capital expenditures should peak in the near term and level off around 2014; we expect cash flow from operations to be largely adequate to fund future capital expenditures.

Free cash flow deficits will continue to be funded with a combination of incremental debt financing and equity support from the parent to maintain leverage at the regulatory-approved levels. Thus, despite the free cash flow deficits, DBRS expects the Company's financial profile and credit metrics to remain adequate for the rating. Key credit ratios are expected to be flat during this elevated capital program period, as increased debt levels will be offset by higher earnings on a growing rate base.

FortisBC Inc.

Report Date:
October 26, 2010

Long-Term Debt Maturities and Liquidity

Debt Chart (CAD millions)

			June 30/10
Secured Debentures			
Guaranteed by FortisWest In		Rate	Amount
Due:	Oct. 2012	9.65%	15.0
	Aug. 2023	8.80%	25.0
WPP Mortgage			
	Oct. 2013	9.44%	3.3
			43.3
Unsecured Debentures			
Guaranteed by FortisWest Inc.			
	Feb. 2016	8.77%	25.0
	Dec. 2021	7.81%	25.0
No Guarantee			
	Nov. 2014	5.48%	140.0
	Nov. 2035	5.60%	100.0
	Jul. 2047	5.90%	105.0
	MTN June 2039	6.10%	105.0
			500.0
Operating Credit Facilties			46.9
Overdraft Facility			10.1
Total Debt			600.3
Less current portion			11.0
Long-Term Debt			589.3

as at June 30, 2010

Maturity Schedule ($MM)	2010	2011	2012	2013	2014	Thereafter	Total
Debt maturities	0.9	0.9	62.9	0.5	140.0	385.0	590.2

As of June 30, 2010, the Company had $590.2 million (excluding the $10.1 million in overdrafts) of total consolidated debt outstanding, including $500 million of unsecured debentures, $43.3 million of secured debt, and $46.9 million of credit facilities.

The secured debt is expected to continue to account for a decreasing percentage of overall debt as the Company funds itself with unsecured debentures. The secured debentures (Series F and G) and the unsecured debentures (Series H and I), totaling $50 million (8.5% of total debt), are guaranteed by FortisWest Inc. (FW). FW is a direct wholly-owned subsidiary of Fortis, whose sole assets consist of shares in FortisBC and FortisAlberta Inc. This debt was outstanding at the time that Fortis Inc. purchased the Company.

The debt profile as of June 30, 2010, is as follows:

- $43.3 million in secured debentures, Series F and G, guaranteed by FW and collateralized by a fixed and floating first charge on the assets of the Company. These debentures mature between 2012 and 2023.
- $50 million in unsecured debentures, Series H and I, which are also guaranteed by FW and mature in 2016 and 2021.
- An additional $345 million of unsecured debentures, issued in three series that mature from 2014 to 2047.
- A $3.3 million mortgage on the Walden power plant, owned and operated by the Walden Power Partnership (WPP), which is secured by a pledge by FortisBC of its interest in the WPP. The mortgage matures October 31, 2013, and bears interest at 9.44%.

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October 26, 2010

FortisBC's operating credit facility was amended in April 2010 and consists of:

- A $100 million, three-year revolving unsecured credit facility, maturing May 8, 2013.
- An additional $50 million, 364-day revolving unsecured credit facility, maturing on May 5, 2011. This facility may be extended for another 364 days or, if not extended, termed out for a six-month period.
- A $10 million demand overdraft facility.

As of June 30, 2010, $57.0 million was utilized against these facilities (December 31, 2009 - $37.8 million) and $nil (December 31, 2009 - $nil) was used to support outstanding letters of credit.

Certain of the Corporation's debt covenants contain restrictions on the payment of dividends if consolidated debt exceeds 70% of consolidated capitalization, if the dividends are not in the ordinary course of business or if the cumulative dividends paid since the date that certain debt instruments were issued exceeds thresholds based on the cumulative net earnings of the Corporation.

Outlook

The Company's $160 million in bank credit facilities should provide sufficient liquidity to meet any short-term funding requirements. As at June 30, 2010, $103 million was available under the credit facilities. The debt repayment schedule is modest. DBRS expects FortisBC to refinance its maturing debt, given its stable credit profile and cash flows generated from its low-risk operations.

Furthermore, DBRS expects additional debt issuance over the medium term to fund the Company's ongoing capital expenditure program.

Description of Operations

FortisBC is a vertically integrated utility operating in south-central British Columbia. The Company serves approximately 159,000 direct and indirect customers, including wholesale customers such as the cities of Kelowna and Nelson.

Approximately 64% of power sold is to relatively stable residential and commercial customers, 6.4% is sold to industrial customers, and 29% is sold to wholesale customers who resell the power to their own residential and commercial customers. FortisBC meets its customers' power requirements through the following sources:

- Four owned hydroelectric plants, with 223 MW of capacity, representing approximately 45% of its energy needs. Electricity production from these plants is insulated from hydrology risk as a result of the Canal Plant Agreement (CPA) between BC Hydro and FortisBC, originally signed in August 1972 and amended in July 2005. Pursuant to the CPA, BC Hydro takes all of the power actually generated by the Company's four plants and delivers a fixed amount of power, currently based on 50-year historical water flows. Since 1998, the Company's hydroelectric facilities have been subject to a life extension and upgrade program, which is expected to conclude in 2012. As a result, total capacity has increased from 205 MW in 2004 to current levels.
- A purchase power contract with the Brilliant hydroelectric plant, which expires in 2056, supplies approximately 28% of the Company's energy needs. The contract includes a market-related price adjustment in 2026. In addition to purchasing the power, FortisBC operates and maintains the plant on behalf of Brilliant.
- Between 2000 and 2002, the Brilliant plant's turbines were upgraded, increasing their output by 125,000 MWh of energy per year. FortisBC acquires an additional 65,000 MWh of energy, as well as 20 MW of capacity from the plant, under an amended PPA.
- A long-term, firm power purchase contract with BC Hydro expiring in 2013, which provides approximately 24.5% of the Company's energy needs.
- A number of small purchase power contracts with independent power producers collectively provide approximately 1% of the Company's energy requirements.
- Any electricity requirements not met by the above sources are satisfied through the spot market.

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FortisBC also has a limited amount of non-regulated operations, principally made up of the WPP, the owner of an independent power producer. The plant is a 16 MW hydroelectric station that sells all of its output to BC Hydro pursuant to a PPA that expires in 2013. The debt of the Partnership is non-recourse to FortisBC.

In 2009, the Company sold 3,157,000 MWh of electricity to its customers, 928,000 MWh of which was purchased by FortisBC's seven wholesale customers. The Company had a peak demand of 714 MW in 2009, 32 MW lower than the historical peak demand of 746 MW.

Regulation

FortisBC is regulated by the BCUC, which is authorized to set electricity rates, the deemed capital structure, the allowed rate of return on deemed common equity, as well as approve and oversee the construction of new projects. Rates are based on a cost-of-service/rate-of-return methodology with some PBR-setting attributes.

FortisBC files annual rate applications for the 12-month period beginning on January 1. On December 18, 2009, the BCUC approved a settlement agreement pertaining to the 2010 Revenue Requirements Application. As a result of the settlement agreement, FortisBC's ROE in 2010 will be 9.90%, up from 8.87% in 2009. The BCUC also determined that the automatic adjustment mechanism that was used to determine the ROE on an annual basis will no longer apply, and the ROE as determined in the decision will apply until changed by the BCUC. Additionally, in December 2009, the BCUC approved a 6% rate increase for 2010. The increase reflected the change in revenue requirement and ROE. The Company's deemed capital structure remains unchanged at 60% debt/40% equity. As at December 31, 2009, FortisBC had total assets of $1.15 billion and Rate Base Assets of $908 million. Rate Base Assets in the 2010 Revenue Requirements are $975 million.

The significant terms of the PBR agreement are as follows:

- Annual gross operating and maintenance expenses before capitalized overhead will be set by a formula incorporating customer growth and inflation (CPI for British Columbia) minus a productivity improvement factor (PIF) of 2% in 2007, 2% in 2008 and, if applicable, 3% in 2009;
- Annual capitalized overhead will be set at 20% of the BCUC-approved gross operating and maintenance expense;
- Other components of revenue requirements will be forecast annually; and
- A 2% collar has been set around the allowed ROE whereby variances (adjusted for certain revenue and cost variances which flow through to customers) as a result of actual financial performance, positive or negative, will be shared equally between customers and the shareholder. If the variance exceeds the 2% collar, the excess will be placed in a deferral account for review and disposition during the next rate setting process. The Company's portion of the incentive is subject to the Company meeting certain performance standards and BCUC approval.

As part of the approval of 2009 Revenue Requirements in December 2008, the PBR agreement was extended for 2009 to 2011. The terms of the settlement are consistent with the May 2006 PBR agreement except that annual gross operating and maintenance expenses before capitalized overhead will be set by formulae incorporating customer growth and inflation (CPI for British Columbia) minus a PIF of 3% in 2009, 1.5% in 2010 and 1.5% in 2011. Should inflation be in excess of 3%, the excess is added to the PIF, which effectively caps the CPI at 3%.

On June 18, 2010, FortisBC applied to the BCUC for approval of its 2011 Capital Expenditure Plan. The plan outlines capital expenditures necessary to provide reliable service, ensure public and employee safety and to deliver Demand Side Management programs to the Company's growing customer base. The $103.3 million plan consists of $97.5 million in capital expenditures, net of customer contributions and $5.8 million in Demand Side Management programs.

FortisBC Inc.

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FortisBC Inc.

Balance Sheet ($ millions)	12 mos. Ending June 30, 2010	As at Dec. 2009	Dec. 2008
Assets			
Cash + equivalents	0.4	0.0	0.0
Accounts receivable/unbilled revenue	33.8	41.1	37.3
Inventories	0.5	0.5	0.7
Other	4.1	3.5	2.1
Current Assets	38.7	45.1	40.2
Net fixed assets	994.0	944.7	873.6
Deferred charges/Goodwill	163.2	157.4	71.8
Total	1196.0	1147.2	985.6

Liabilities & Equity	12 mos. Ending June 30, 2010	As at Dec. 2009	Dec. 2008
Short-term debt	0.0	0.0	0.0
Debt due one yr.	11.0	3.7	61.8
A/P + accr'ds	56.8	49.3	51.9
Current Liabilities	67.8	53.0	113.7
Long-term debt	540.7	528.6	418.0
Secured debt	43.3	43.7	47.5
Capital lease obligations	32.2	28.9	28.7
Other l.t. liabilities	100.7	96.0	12.6
Shareholders' equity	411.4	396.9	365.2
Total	1196.0	1147.2	985.6

Ratio Analysis	12 mos. Ending	For the 12-month period ended			
Liquidity Ratios	June 30, 2010	Dec. 2009	Dec. 2008	Dec. 2007	Dec. 2006
Current ratio	0.57	0.85	0.35	0.84	0.72
Accumulated depreciation/gross fixed assets	20.4%	21.4%	22.1%	22.0%	22.7%
Cash flow/adjusted debt (1)	12.4%	12.2%	11.4%	11.4%	11.2%
Cash flow/capital expenditures	0.60	0.69	0.62	0.45	0.53
Cash flow-dividends/capital expenditures	0.49	0.56	0.49	0.37	0.43
% debt in capital structure	60.4%	60.4%	60.4%	61.1%	60.9%
% adjusted debt in capital structure (1)	60.7%	61.0%	60.9%	61.7%	61.6%
Deemed common equity	40.0%	40.0%	40.0%	40.0%	40.0%
Coverage Ratios (1)					
EBIT interest coverage	2.03	2.04	2.05	2.04	2.11
EBITDA interest coverage	3.09	3.06	3.09	3.04	3.09
Fixed-charges coverage	2.03	2.04	2.05	2.04	2.11
Adjusted debt/EBITDA	5.59	5.64	5.60	5.69	5.67
Earnings Quality/Operating Efficiency					
Power purchases/revenues	28.6%	29.3%	29.7%	31.0%	32.6%
EBIT margin	30.1%	29.9%	29.4%	28.5%	27.6%
Net margin (before extras)	15.1%	14.8%	14.2%	13.7%	12.8%
Return on avg. common equity (before extras)	9.2%	9.5%	9.4%	9.6%	9.5%
Allowed ROE – mid-point	9.90%	8.87%	9.02%	8.77%	9.20%
Direct customers/employee	205	204	201	202	181
Growth of customer base	0.4%	1.1%	2.3%	1.2%	1.9%
Rate base ($ millions)	949.0	867.7	822.8	747.2	676.0
Growth in rate base	9.4%	5.5%	10.1%	10.5%	14.3%

(1) Adjusted for operating leases.

SUMMARY OF OPERATING STATISTICS

	12 mos. Ending	For the 12-month period ended				
Generation	June 30, 2010	Dec. 2009	Dec. 2008	Dec. 2007	Dec. 2006	Dec. 2005
Hydro capacity (MW)	223	223	223	223	235	214
Gross energy generated (GWh)	1,544	1,539	1,610	1,498	1,509	1,625
Plus: purchases	1,802	1,909	1,790	1,912	1,896	1,724
Energy generated + purchased	3,346	3,448	3,400	3,410	3,405	3,349
Less: transmission losses + internal use	277	291	313	320	365	378
Total GWh sold	3,069	3,157	3,087	3,090	3,040	2,971
Energy lost + used/energy gen. + purch.	8.3%	8.4%	9.2%	9.4%	10.7%	11.3%

FortisBC Inc.

Report Date:
October 26, 2010

Rating

Debt	Rating	Rating Action	Trend
Secured Debentures	A (low)	Upgraded	Stable
Unsecured Debentures	A (low)	Upgraded	Stable

Rating History

	Current	2009	2008	2007	2006	2005
Secured Debentures	A (low)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)
Unsecured Debentures	A (low)	BBB (high)	BBB (high)	BBB (high)	BBB (high)	BBB (high)

Note:
All figures are in Canadian dollars unless otherwise noted.

Appendix J

2011 DEPRECIATION STUDY

FortisBC, Inc.

KELOWNA, BRITISH COLUMBIA

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES APPLICABLE TO PLANT IN SERVICE AT DECEMBER 31, 2009

Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania **Calgary, Alberta** **Valley Forge, Pennsylvania**

Gannett Fleming
Valuation and Rate Division

GANNETT FLEMING, INC.
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June 6, 2011

FortisBC, Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC
V1Y 7P7

Attention: Ms. Michele Leeners
Vice President of Finance and Chief Financial Officer

Dear Ms. Leeners:

Pursuant to your request, we have conducted a depreciation study related to the electric generation, transmission and distribution system of FortisBC, Inc. as of December 31, 2009. Our report presents a description of the methods used in the estimation of depreciation and net salvage, the statistical analyses of service life and the summary and detailed tabulations of annual and accrued depreciation.

The calculated annual depreciation accrual rates presented in the report are applicable to plant in service as of December 31, 2009. The depreciation rates are based on the straight-line method, the remaining life basis, using the average service life group procedure. An annual review of the depreciation rates using the same estimates and methods is recommended.

Respectfully submitted,
GANNETT FLEMING, INC.

LARRY E. KENNEDY
Director, Canadian Services
Valuation and Rate Division

LEK/hac
Project: 053630

A Tradition of Excellence

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PART I. INTRODUCTION

FORTISBC, INC.

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES APPLICABLE TO PLANT IN SERVICE AT DECEMBER 31, 2009

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study conducted for the electric generation, transmission and distribution assets of FortisBC, Inc. ("Fortis") to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of plant at December 31, 2009.

The depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The estimated survivor curves and estimated net salvage percents used in this report are based on studies incorporating data through 2009.

Part I, Introduction, contains statements with respect to the scope of the report and the basis of the study. Part II, Methods Used in the Estimation of Depreciation, presents the methods used in the estimation of average service lives, survivor curves and net salvage and in the calculation of depreciation. Part III, Results of Study, presents a summary of annual depreciation. Parts IV through VI, present the statistical analyses of service lives, net salvage estimates, and the detailed tabulations of annual depreciation, respectively.

BASIS OF THE STUDY

Depreciation. The annual depreciation accrual, and cost of removal rates and the related calculated requirement for accumulated depreciation and cost of removal were calculated using the straight line method, the remaining life basis and the average service life (ASL) procedure. The calculation was based on the attained ages and estimated service life and net salvage characteristics for each depreciable group of assets.

Service Life and Net Salvage Estimates. The method of estimating service life consisted of compiling the service life history of the plant accounts and subaccounts, reducing this history to trends through the use of analytical techniques that have been generally accepted in various regulatory jurisdictions, and forecasting the trend of survivors for each depreciable group on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of the historical trend and the estimated future trend yielded a complete pattern of life characteristics from which the average service life was derived. The service life estimates used in the depreciation calculation incorporated historical data compiled through December 31, 2009. Such data included plant additions, retirements, transfers and other plant activity.

A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement was obtained through discussions with operating and management personnel in this study, and previous site tours of the generation, transmission and distribution facilities of the company. Throughout these interviews and site tours, an analysis of the accounting procedures and policies was also undertaken by Gannett Fleming in order to determine the reasonableness of the historic retirement transactions.

The estimates of net salvage were based in part on historical data compiled through 2009, and in part through knowledge gained in the operational staff interviews and site tours. Additionally, Gannett Fleming has significant experience in the development of net salvage percentage estimates, and included this background and experience in the development of recommended net salvage percentages as well.

RECOMMENDATIONS

The calculated annual depreciation accrual and cost of removal rates set forth herein apply specifically to plant in service as of December 31, 2009. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate depreciation rates.

The depreciation rates should be reviewed periodically if there are indications that plant and accumulated depreciation account activity may result in materially different depreciation rates. The survivor curves, net salvage percents, and amortization periods used in this study should be the basis for periodic recalculations. Complete depreciation studies, which reevaluate these parameters, should be performed every three to five years.

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

The calculation of annual and accrued depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. These subjects are discussed in the sections that follow.

ESTIMATION OF SURVIVOR CURVES

Survivor Curves. The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval and is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

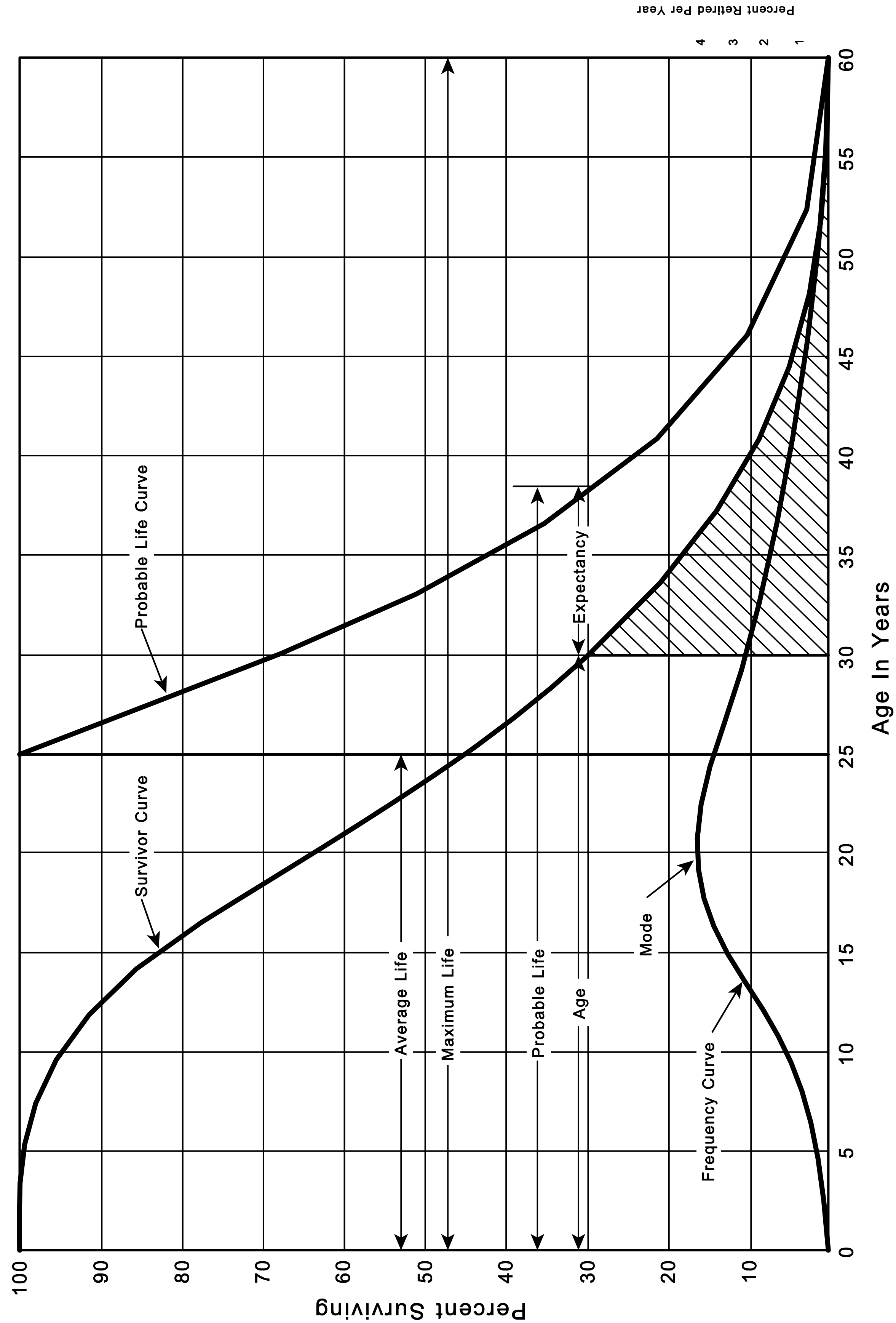


Figure 1. A Typical Survivor Curve and Derived Curves

Iowa Type Curves The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student

[1] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

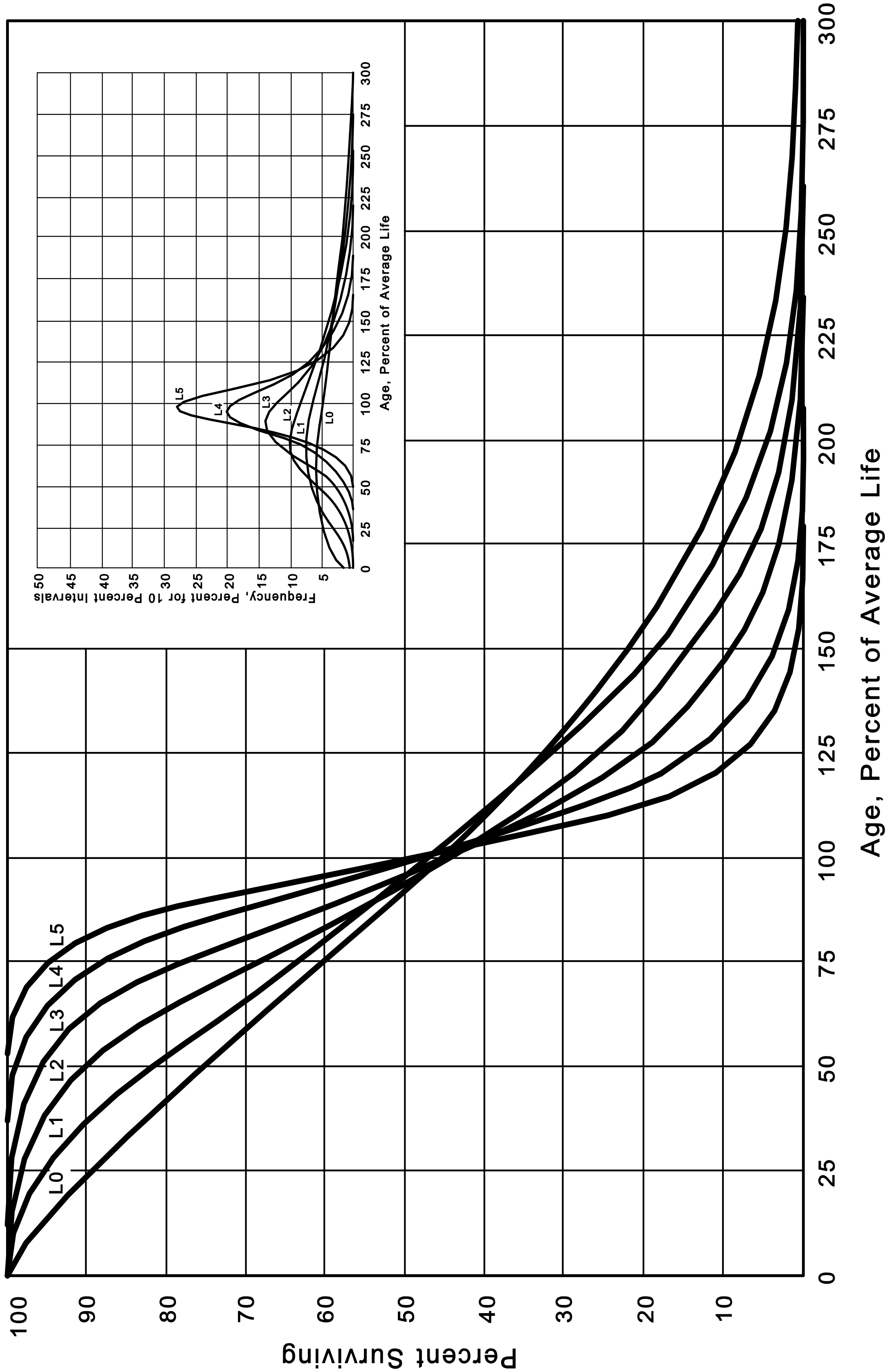


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

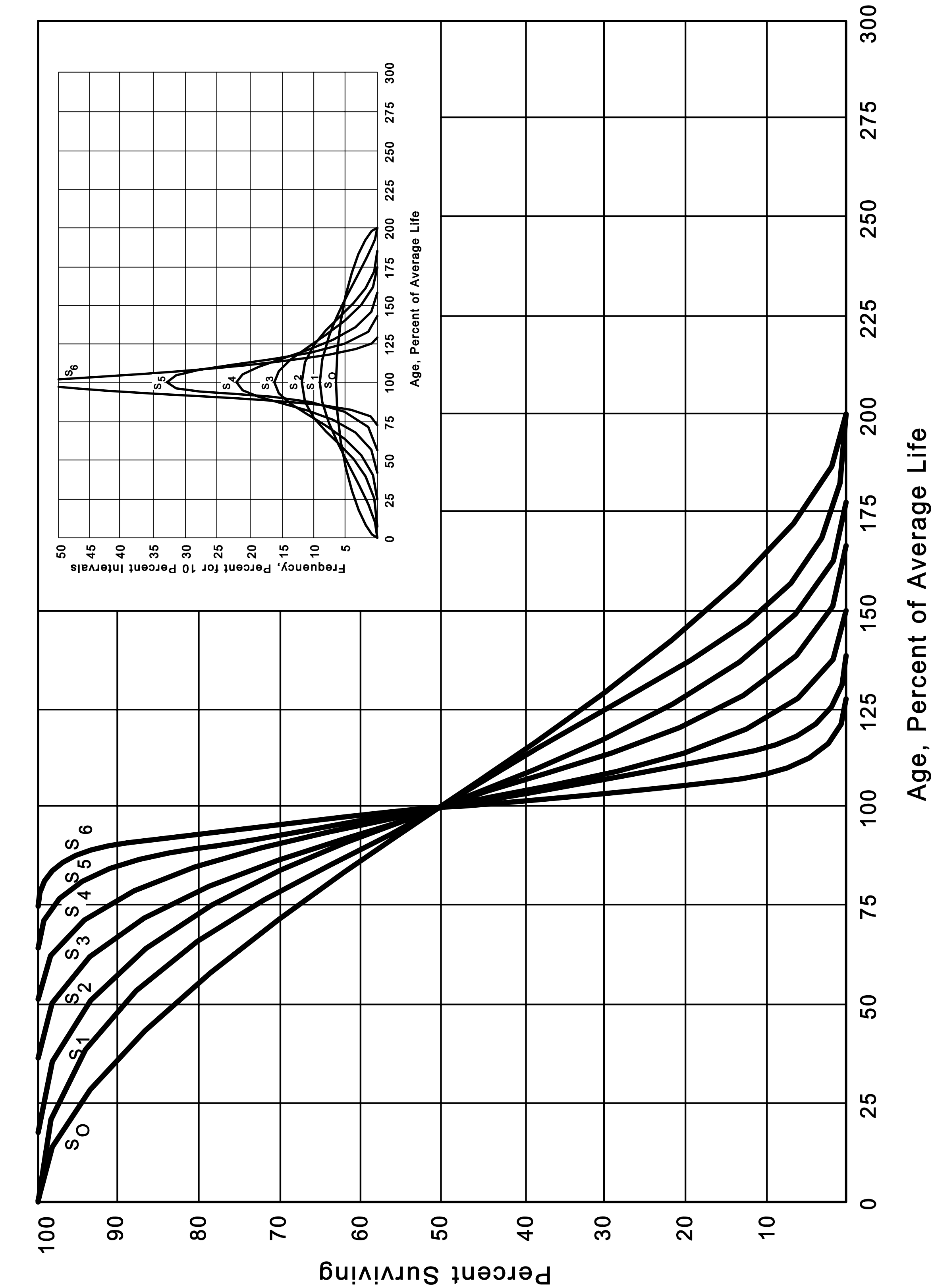


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

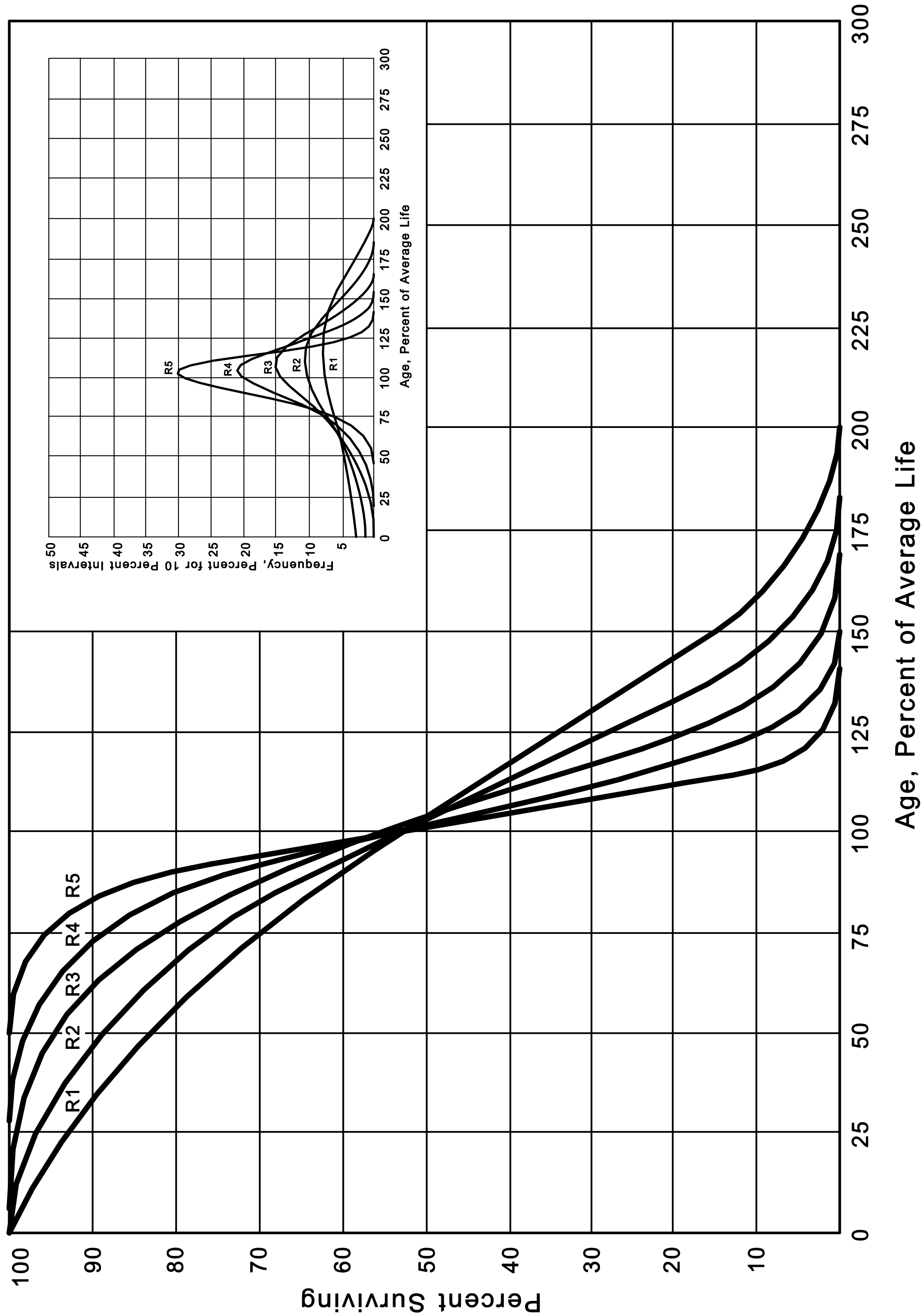


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

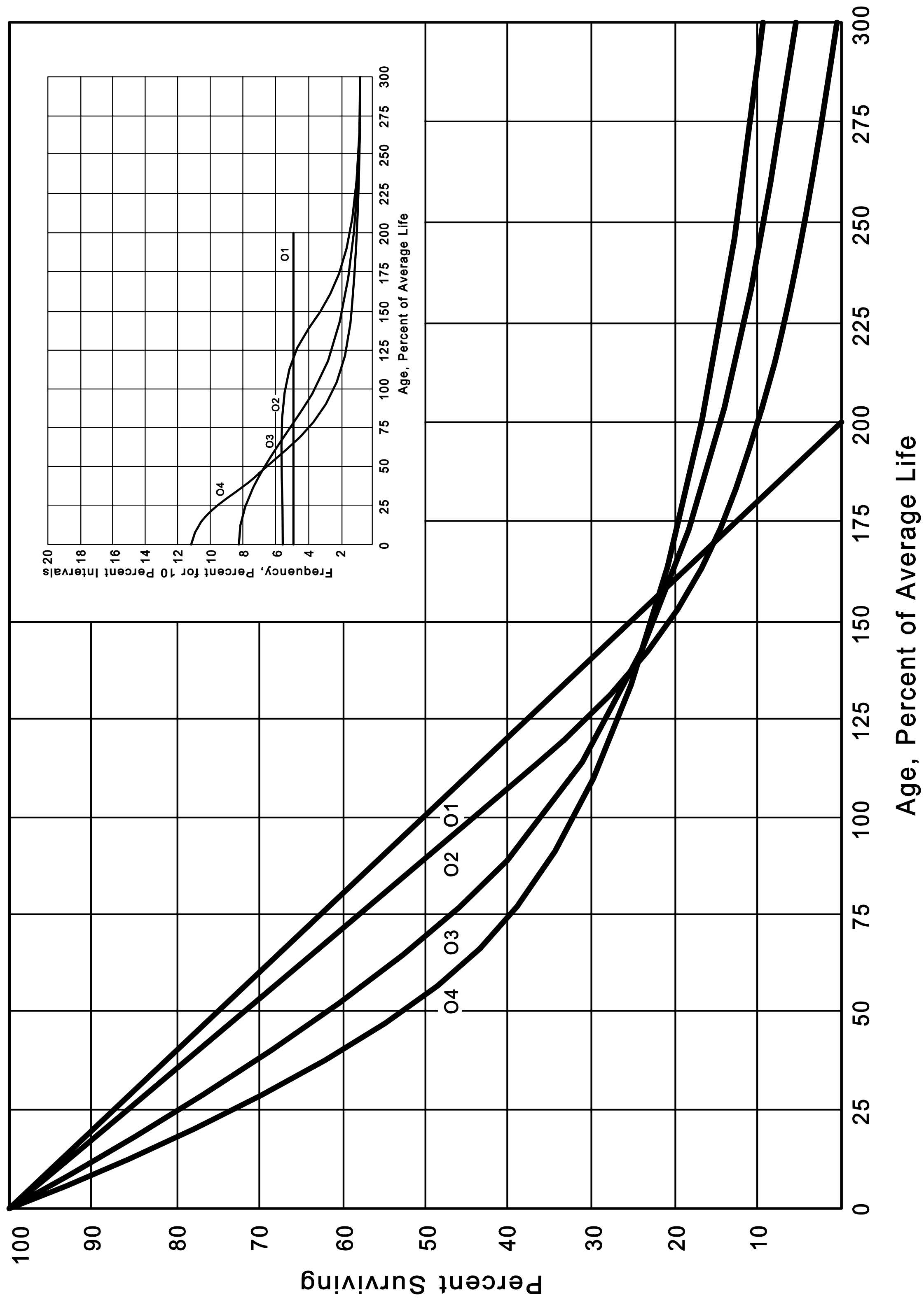


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

submitted a thesis[2] presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis. The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging un-aged amounts and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[3] "Engineering Valuation and Depreciation,"[4] and "Depreciation Systems."[5]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginnings of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual

[2]Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

[3]Winfrey, Robley, Supra Note 1.

[4]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.

[5]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994

aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records. The property group used to illustrate the retirement rate method is observed for the experience band 2001-2009 during which there were placements during the years 1996-2009. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Tables 1 and 2 on the following pages. In Table 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, \$10,000 of the dollars invested in 1996 were retired in 2001. The \$10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of \$143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Table 1 immediately above the stairstep line drawn on the table beginning with the 2001 retirements of 1996 installations and ending with the 2009 retirements of the 2005 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

TABLE 1. RETIREMENTS FOR EACH YEAR 2000-2009
SUMMARIZED BY AGE INTERVAL

Experience Band 2000-2009 | Placement Band 1995-2009

Year Placed	Retirements, Thousands of Dollars During Year 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total During Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1995	10	11	12	13	14	16	23	24	25	26	26	13½-14½
1996	11	12	13	15	16	18	20	21	22	19	44	12½-13½
1997	11	12	13	14	16	17	19	21	22	18	64	11½-12½
1998	8	9	10	11	11	13	14	15	16	17	83	10½-11½
1999	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2000	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2001		5	11	12	13	14	15	16	18	20	113	7½-8½
2002			6	12	13	15	16	17	19	19	124	6½-7½
2003				6	13	15	16	17	19	19	131	5½-6½
2004					7	14	16	17	19	20	143	4½-5½
2005						8	18	20	22	23	146	3½-4½
2006							9	20	22	25	150	2½-3½
2007								11	23	25	151	1½-2½
2008									11	24	153	½-1½
2009										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

TABLE 2. OTHER TRANSACTIONS FOR EACH YEAR 2000-2009
SUMMARIZED BY AGE INTERVAL

Experience Band 2000-2009 | Placement Band 1995-2009

	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
Placed (1)	2000 (2)	2001 (3)	2002 (4)	2003 (5)	2004 (6)	2005 (7)	2006 (8)	2007 (9)	2008 (10)	2009 (11)	Total During Age Interval (12)	Age Interval (13)
1995	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
1996	-	-	-	-	-	-	-	-	-	-	-	12½-13½
1997	-	-	-	-	-	-	-	-	-	-	-	11½-12½
1998	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
1999	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2000		-	-	-	-	-	-	-	-	-	(5)	8½-9½
2001			-	-	-	-	-	-	-	-	-	7½-8½
2002			-	-	-	-	-	-	-	-	-	6½-7½
2003				-	-	-	-	(12)[b]	-	-	-	5½-6½
2004					-	-	-	-	22[a]	-	-	4½-5½
2005						-	-	(19)[b]	-	-	10	3½-4½
2006							-	-	-	-	-	2½-3½
2007								-	-	(102)[c]	(121)	1½-2½
2008									-	-	-	½-1½
2009											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount.

In Table 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement. The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Table 3 on page II-16. The surviving plant at the beginning of each year from 2001 through 2009 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Table 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Tables 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2006 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

For the entire experience band 2001-2009, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Table 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table. The original life table, illustrated in Table 4 on page II-19, is developed from the totals shown on the schedules of retirements and exposures, Tables 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Tables 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

TABLE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2001-2009
SUMMARIZED BY AGE INTERVAL

Experience Band 2001-2009 | Placement Band 1996-2009

	Exposures, Thousands of Dollars											
	Annual Survivors at the Beginning of the Year											
Year Placed (1)	2001 (2)	2002 (3)	2003 (4)	2004 (5)	2005 (6)	2006 (7)	2007 (8)	2008 (9)	2009 (10)	2009 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
1996	255	245	234	222	209	195	239	216	192	167	167	13½-14½
1997	279	268	256	243	228	212	194	174	153	131	323	12½-13½
1998	307	296	284	271	257	241	224	205	184	162	531	11½-12½
1999	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2000	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2001	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2002		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2003			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2004				580[a]	574	561	546	530	501	482	3,057	5½-6½
2005					660[a]	653	639	623	628	609	3,789	4½-5½
2006						750[a]	742	724	685	663	4,332	3½-4½
2007							850[a]	841	821	799	4,955	2½-3½
2008								960[a]	949	926	5,719	1½-2½
2009									1,080[a]	1,069	6,579	½-1½
2009											7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

The original survivor curve is plotted from the original life table (column 6, Table 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve. The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Table 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

TABLE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2001-2009 Placement Band 1996-2009

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Table 3, Column 12, Plant Exposed to Retirement.
Column 3 from Table 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

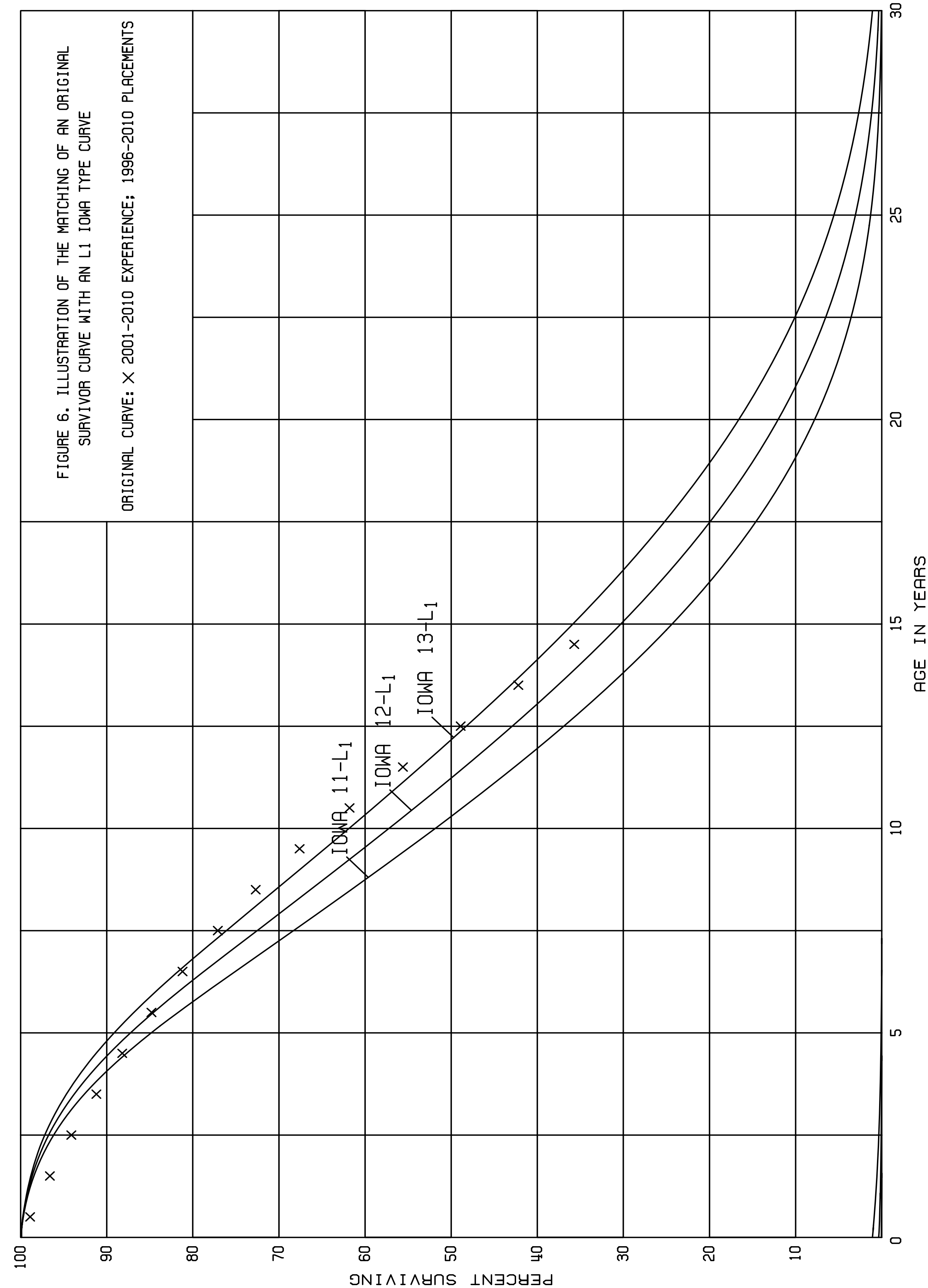


FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE

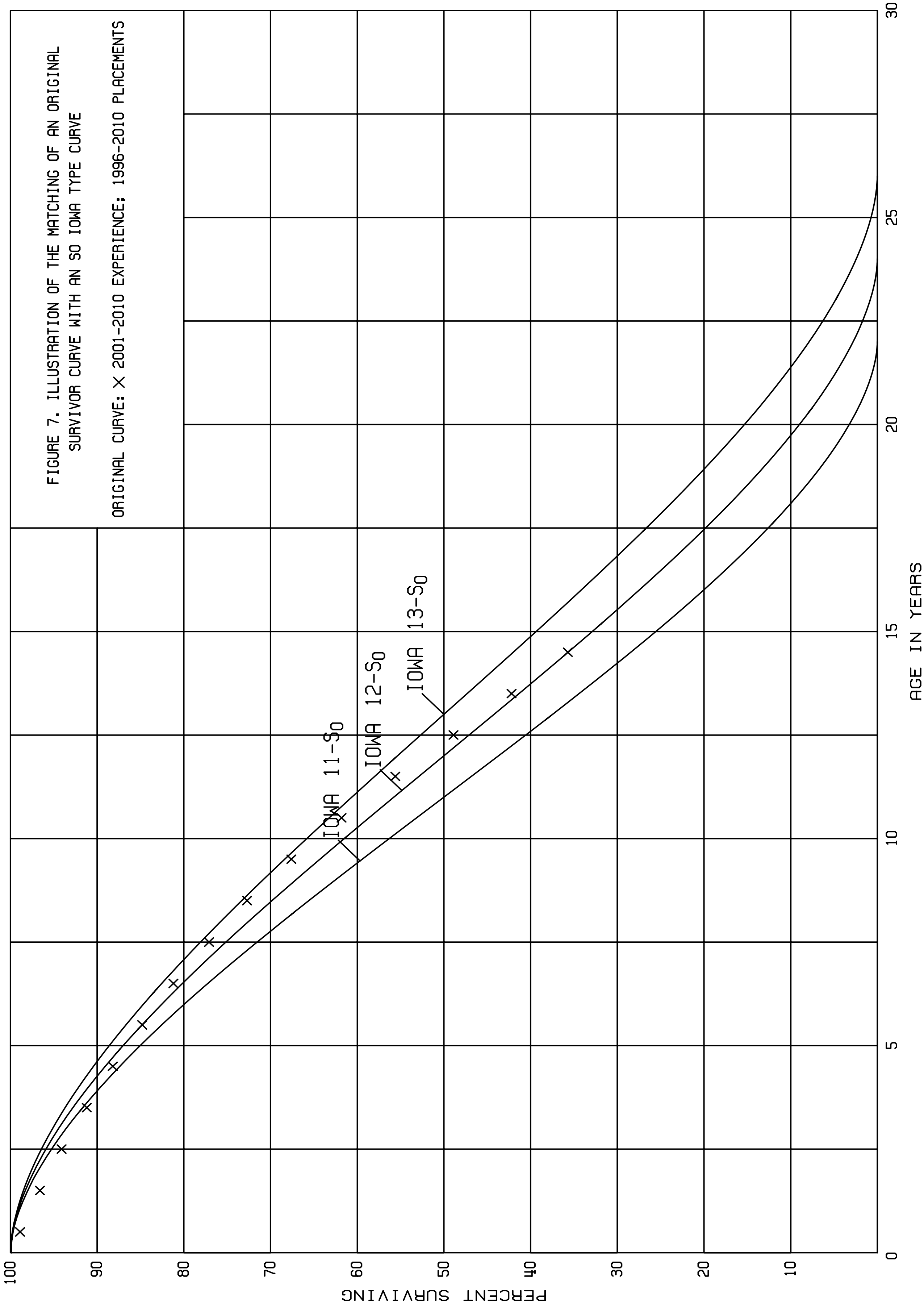


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN SO IOWA TYPE CURVE

ORIGINAL CURVE: × 2001-2010 EXPERIENCE; 1996-2010 PLACEMENTS

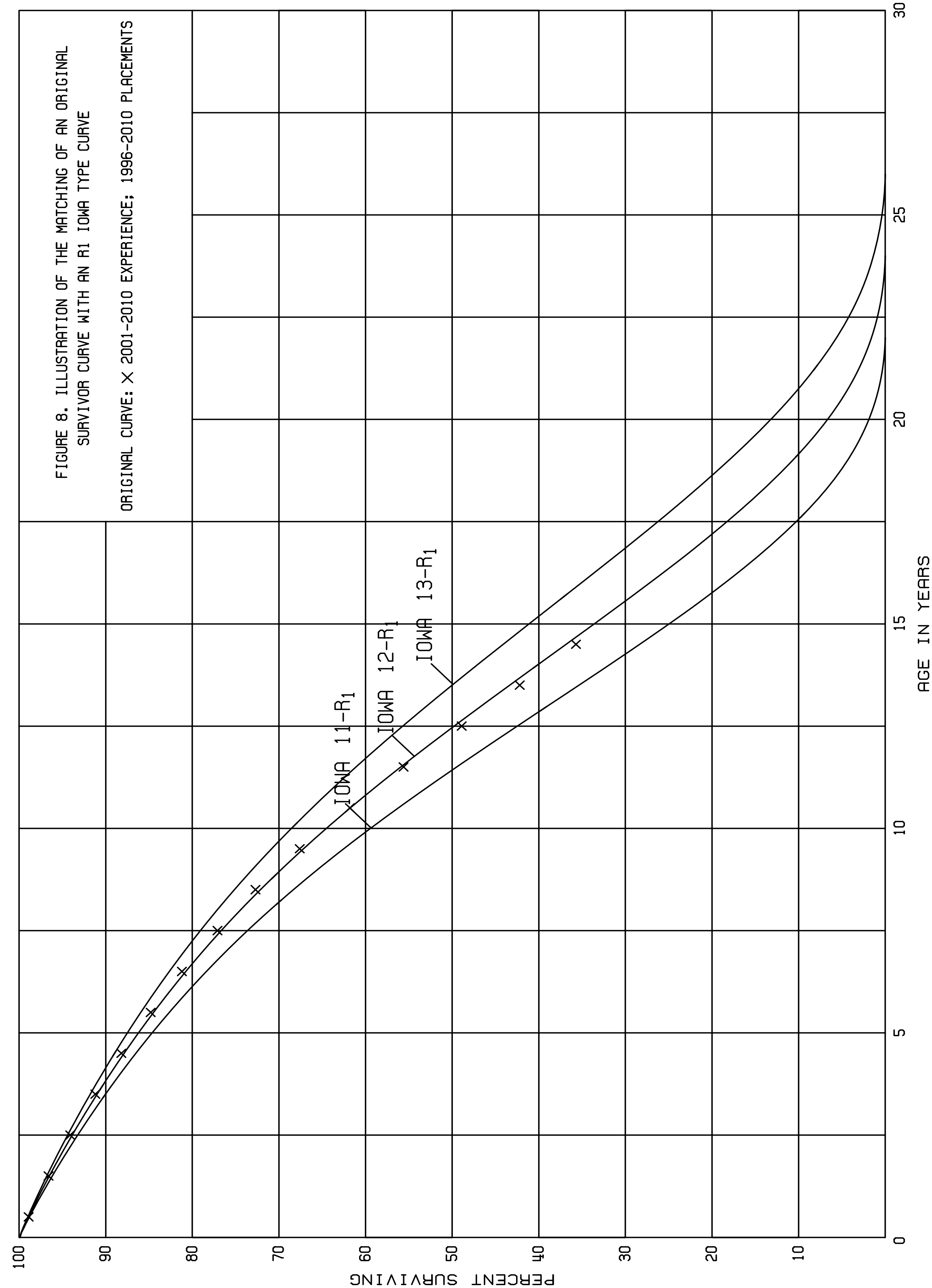


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE

ORIGINAL CURVE: × 2001-2010 EXPERIENCE; 1996-2010 PLACEMENTS

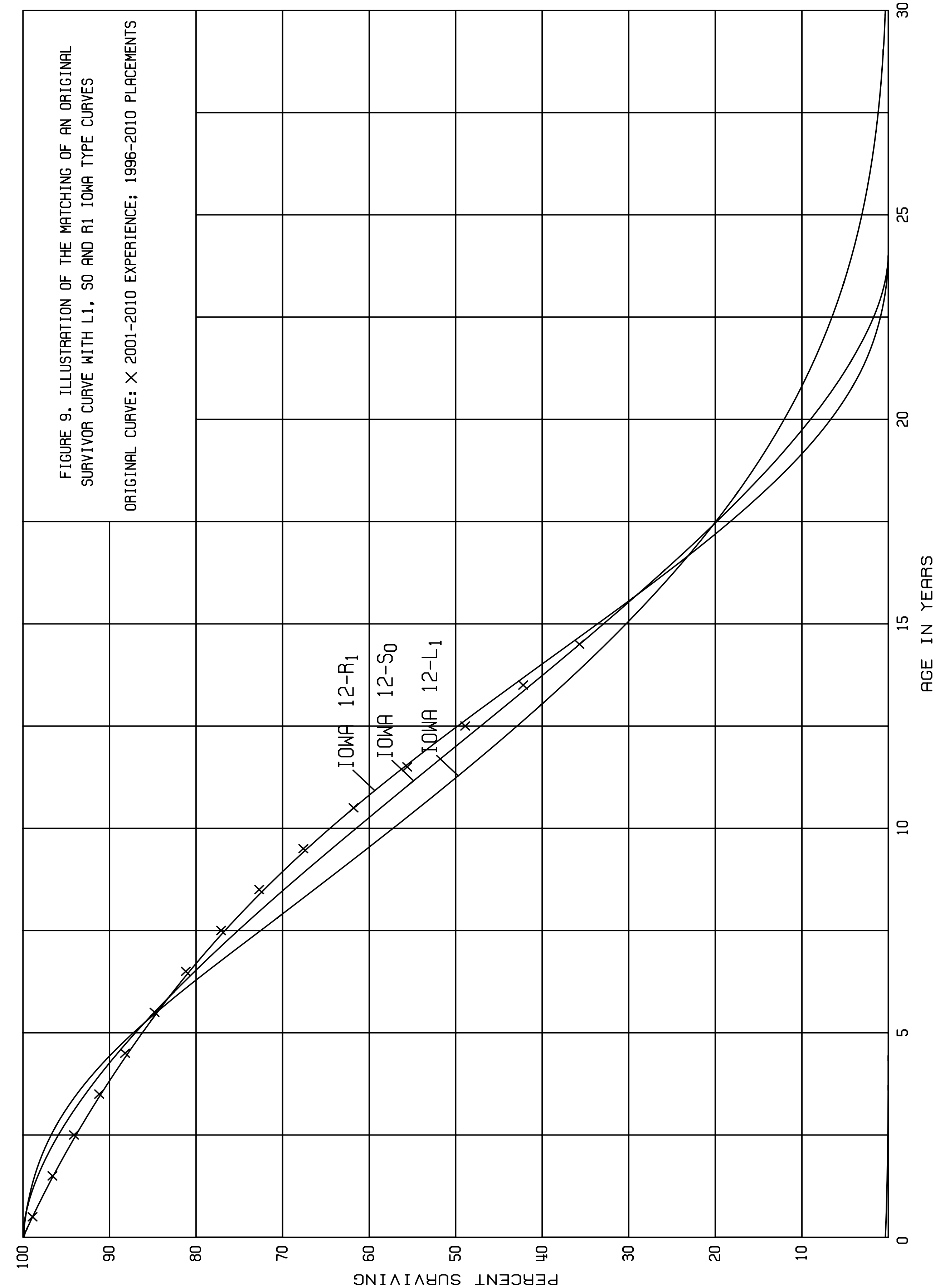


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH L1, S0 AND R1 IOWA TYPE CURVES
ORIGINAL CURVE: × 2001-2010 EXPERIENCE; 1996-2010 PLACEMENTS
IOWA 12-R1
IOWA 12-S0
IOWA 12-L1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

Survivor Curve Judgments. The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined through conversations conducted as part of this study with operations and management personnel; incorporating the knowledge that Gannett Fleming has gained through the completion of a number of Fortis assignments over a number of years; and survivor curve estimates from previous studies of this Company and other electric distribution companies.

Account 365.00 - Distribution Conductors and Devices, represents 17% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960-2009 were analyzed by the retirement rate method. The original survivor curve as plotted on page IV-46, indicates retirement ratios that begin to increase at age 13 and continue with high retirement ratios thereafter. Staff interviews did not indicate any significant reason that the future retirement patterns will vary from those experienced in the past. While it is considered that this account will experience growth over the next few years, given expected growth in the distribution service areas, the historic retirement trends are expected to continue into the future. The life of this account has been increased from 40 to 45. As such, the Iowa 45-R3 selected for this account fits well to the historic retirement patterns and is expected to be indicative of the future retirement patterns.

<u>Account 362.00 - Distribution Station Equipment</u>, represents 15% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960 through 2009 were analyzed by the retirement rate method. The original survivor curve as plotted on page IV-40, indicates small retirement ratios early in the assets life and increase in frequency at approximately ages 13, 26 and 36. The company has recently finished upgrading a number of the older distribution substation facilities. It is not anticipated that the new assets which were installed will have different retirement patterns than the ones they have replaced. The Iowa 55-S3 was selected and is a better match for the historical data then the current Iowa 45-R2.5. The Iowa 55-S3, provides a reasonable interpretation of the historical retirement experience and recognizes the expectation that future retirements will most likely follow the same trends as the past.

<u>Account 353.00 - Transmission Substation Equipment</u>, represents 11% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960 through 2009 were analyzed by the retirement rate method. This account consists primarily of the investment in transmission substations. As indicated in the original survivor curve as plotted at page IV-26, this account has historically been subjected to only very modest retirement activity. Recently Fortis has constructed a number of new terminal stations as well as rebuilt some of the existing substations. The company does not expect to continue building with the same frequency in the future and does not believe these new builds with have a different retirement pattern than the historic indications. The movement from an Iowa 50-S3 to a 50-S4, provides a more reasonable interpretation of the historical retirement experience and recognizes the expectation that future retirements will most likely follow the same trends as the past.

Account 368.00 - Distribution Line Transformers, represents 8% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960 through 2009 were analyzed by the retirement rate method. This account consists mainly of the lower voltage overhead and pad mounted line transformers used in the distribution of electric power within the company's service area. The original survivor curve as plotted on page IV-49, indicates retirement ratios that begin early in the accounts life and continue with relatively consistent retirement ratios through age 43, with remaining plant retiring quickly thereafter. Operational and management staff interviews did not indicate any significant reason that the future historic retirement patterns will vary from those experienced in the past. While it is considered that this account will experience growth over the next few years, given expected growth in the distribution service areas, to better fit the historical data a movement from the Iowa 45-L2.5 to 45-R4 was selected for this account. The 45-R4 curve is a good fit to the historic retirement patterns and is expected to be indicative of the future retirement patterns.

Account 364.00 – Distribution Poles, Towers and Fixtures, represents 10% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960 through 2009 were analyzed by the retirement rate method. This account consists of the distribution power poles, the insulators and attachments to the power poles such as cross -arms and guy wires. As indicated in the original survivor curve as plotted on page IV-43 this account has witnessed a significant amount of retirement activity within the experience band analyzed, with the pace of retirement ratios increasing at approximately age 27. While it is expected that this account will continue to experience growth over the next number of years, it is also expected that the retirement activity in this account in the future will follow a similar dispersion as that witnessed over the last number of years. As such the Iowa 50-R3 selected for this account provides a good fit to the historical retirement patterns and is considered to be reflective of the future retirements in this account.

Account 355.00 – Transmission Poles, Towers and Fixtures, represents 6% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960 through 2009 were analyzed by the retirement rate method. This account consists of the transmission, towers, poles, insulators and attachments, such as guy wires and anchors. In 2004, 380 km of 60Kv transmission lines was removed. Discussions with operating staff indicate that the account did experience a significant level of plant retirements over past few years due to required system improvements and upgrades of aging plant. Management has indicated future builds and retirements will occur as needed but are not expected to be similar in number or significance as the past 3 years. Therefore, the Iowa curve has shifted from 45-S2 to 50-R3 and is considered to be reflective of the estimated future retirement patterns.

Account 356.00 - Transmission Conductors and Devices, represents 6% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960 through 2009 were analyzed by the retirement rate method. This account consists mainly of the Transmission conductor, and related material required for the electric transmission of electricity. As indicated in the original survivor curve as plotted at page IV-32, this account has witnessed a significant amount of retirement activity within the experience band analyzed. Retirements in this account have begun at a relatively early age and significantly increased in frequency at age 30 and continued at a high frequency through to age 50. Discussions with management and company staff indicate that further retirement activity will likely be similar to the historic levels. As such, the currently approved Iowa 50-R3 has been modified to 60-R3 for this account which provides a reasonable interpretation of the historical retirement experience and recognizes the expectation that future retirements will occur in a similar pattern as the historic retirement activity.

Account 335.00 - Generation Plant - Other Power Plant Equipment, represents 3% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960 through 2009 were analyzed by the retirement rate method. This account consists mainly of the Transmission conductor, and related material required for the electric transmission of electricity. As indicated in the original survivor curve as plotted at page IV-26, this account has witnessed only limited amounts of retirement activity within the experience band analyzed. Discussions with management and company staff indicate that further retirement activity will likely be similar to the historic levels. As such, the Iowa curve 45-R4 is recommended for this account as it provides a reasonable interpretation of the historical retirement experience and recognizes the expectation that future retirements will occur in a similar pattern as the historic retirement activity.

Account 334.00 - Generation Plant - Accessory Electrical Equipment, represents 2% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1960 through 2009 were analyzed by the retirement rate method. As indicated in the original survivor curve as plotted at page IV-14, this account has witnessed some retirement activity within the experience band analyzed. Retirements in this account have begun at a relatively early age with more significant amount of retirements from ages 12 to 24. Discussions with management and company staff indicate that further retirement activity will likely be similar to the historic levels. The currently approved Iowa 45-R2.5 has been modified to the Iowa curve 50-R3 for this account which provides a reasonable interpretation of the historical retirement experience and recognizes the expectation that future retirements will occur in a similar pattern as the historic retirement activity.

All other accounts, which individually represent less than 2% of the depreciable plant studied were analyzed using similar methods and considered similar factors.

ESTIMATION OF NET SALVAGE

The estimates of net salvage were based, in part on historical data for the years 1995 through 2009 and in part on the professional judgment of Gannett Fleming. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Percentages of the cost of plant retired were calculated for each component of net salvage on both annual and five-year moving average bases. Additionally, the historic trends of the net salvage percentages were compared to other electric utilities, and were modified based on the judgment and experience of Gannett Fleming.

When a utility retires plant, the plant may be: sold to a third party; reused by the utility for additional service; abandoned in place; or physically removed. In the circumstances where the plant is sold or re-used a salvage proceed (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the accounts original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage percentage results.

The estimation of the net salvage percentages developed using the traditional approach, included the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period January 1, 1995 through December 31, 2009 were extracted from the plant accounting systems.

2. A net salvage amount (gross salvage proceeds less cost of retirement) was calculated for each historic year. Additionally, a net salvage amount was also calculated for each historic 3-year rolling band.

3. The net salvage amount determined above was compared to the original booked costs retired for each period in the manner described, which resulted in a net salvage percentage of original costs retired for each year, in addition to 3-year rolling bands.

4. The annual, and 3-year rolling average net salvage percentages were analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage was based purely upon statistical analysis.

5. Each account was then analyzed based on the statistical analyses, the information provided by the operations groups regarding the current projects, and with the professional judgment of Gannett Fleming. Based on this analysis, a net salvage percentage for each account was determined.

6. The net salvage percentage was then used in the depreciation rate calculations in the technical update.

The annual, five-year and three-year net salvage percentage calculations are presented in account order in Part IV of this report.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures. When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group.

In the average service life procedure, the rate of annual depreciation is based on the average life or average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life. In this procedure, the accrued depreciation is based on the average service life of the group and the average remaining life of each vintage within the group derived from the area under the survivor curve between the attained age of the vintage and the maximum age.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

The deprecation rates calculated in this study incorporated the use of the ASL procedure.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable plant in service. The general plant accounts and their amortization periods are as follows:

	Account	Amortization Period, Years
391.0	Office Furniture and Equipment	15
391.1	Computer Equipment and Software	10
391.2	PC Computer Equipment and Software	5
394.0	Tools and Work equipment	15
397.0	Communications Structures and Equipment	15

For the purpose of calculating annual amortization amounts as of December 31, 2009, the book depreciation reserve for each plant account is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculation of the composite remaining lives, and the determination of the annual and accrued depreciation related to investment (and separately for cost of removal) are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line method, using the average service life procedure, applied on a remaining life basis, based on estimates which reflect considerations of current historical evidence and expected future conditions.

DESCRIPTION OF DETAILED TABULATIONS

The service life and net salvage estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in the section beginning on page IV-2.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table plotted on the chart is presented. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the charts indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

Detailed calculations of the net salvage percentage are presented in account sequence for each account where a historic analysis of net salvage was available in the section beginning at page V-2. The detailed analysis provides the annual net salvage calculations for each year from 1995 through 2009 inclusive, as well as the moving three-year average and the most recent five-year average.

The tables of the calculated annual depreciation applicable to plant as of December 31, 2009 are presented in account sequence starting at page VI-2. The tables indicate the estimated average survivor curves and net salvage percents used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual.

FORTISBC, INC.

SCHEDULE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE (%)	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GENERATION PLANT								
330.10	LAND RIGHTS	75-R4	0	961,358	(709,439)	1,670,797	36,531	3.80	45.7
331.00	STRUCTURES AND IMPROVEMENTS	60-L3	0	12,015,310	4,714,257	7,301,053	154,738	1.29	47.2
332.00	RESERVOIRS, DAMS, AND WATERWAYS	70-R4	0	24,443,427	3,290,720	21,152,707	492,446	2.01	42.9
333.00	WATER WHEELS, TURBINES, AND GENERATORS	75-R3	0	61,382,405	4,165,975	57,216,430	1,197,917	1.95	47.8
334.00	ACCESSORY ELECTRICAL EQUIPMENT	50-R3	0	27,493,467	7,725,117	19,768,350	648,832	2.36	30.4
335.00	OTHER POWER PLANT EQUIPMENT	45-R4	0	40,893,990	8,029,184	32,864,806	947,694	2.32	34.7
336.00	ROADS, RAILROADS AND BRIDGES	75-S4	0	1,287,435	233,134	1,054,301	19,214	1.49	54.9
	TOTAL GENERATION PLANT			**168,477,392**	**27,448,948**	**141,028,444**	**3,497,372**	**2.08**	
	TRANSMISSION PLANT								
350.10	LAND RIGHTS	75-R3	0	5,798,520	1,103,235	4,695,285	85,106	1.47	55.2
353.00	SUBSTATION EQUIPMENT	50-S4	0	138,236,257	29,775,810	108,460,447	4,758,609	3.44	22.8
355.00	POLES, TOWERS AND FIXTURES	50-R3	0	72,712,210	17,470,103	55,242,107	1,922,254	2.64	28.8
356.00	CONDUCTORS AND DEVICES	60-R3	0	70,447,452	14,363,421	56,084,031	1,442,900	2.05	38.9
359.00	ROADS AND TRAILS	40-R0.5	0	1,121,930	55,044	1,066,886	30,050	2.68	35.5
	TOTAL TRANSMISSION PLANT			**288,316,368**	**62,767,613**	**225,548,755**	**8,238,919**	**2.86**	
	DISTRIBUTION PLANT								
360.10	LAND RIGHTS	75-R3	0	8,477,101	472,271	8,004,830	225,551	2.66	35.5
362.00	SUBSTATION EQUIPMENT	55-S3	0	181,230,662	32,248,509	148,982,153	3,986,601	2.20	37.4
364.00	POLES, TOWERS AND FIXTURES	50-R3	0	126,978,444	34,246,501	92,731,943	2,706,149	2.13	34.2
365.00	CONDUCTORS AND DEVICES	45-R3	0	208,986,680	49,392,215	159,594,465	5,366,420	2.57	29.7
368.00	LINE TRANSFORMERS	45-R4	0	98,456,668	15,995,063	82,461,605	3,360,316	3.41	24.6
369.00	SERVICES	75-R4	0	7,292,398	6,475,852	816,546	11,420	0.16	71.5
370.00	METERS	20-R1	0	13,276,592	6,809,246	6,467,346	887,446	6.68	7.3
371.00	INSTALLATIONS ON CUSTOMERS PREMISES	20-R1	0	937,832	937,832	-	-	-	0.0
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	40-R4	0	10,274,609	1,482,786	8,791,823	2,361,225	22.98	3.7
	TOTAL DISTRIBUTION PLANT			**655,910,986**	**148,060,275**	**507,850,711**	**18,905,128**	**2.88**	
	GENERAL PLANT								
390.00	STRUCTURES - FRAME AND IRON	40-R3	0	337,364	266,696	70,668	2,384	0.71	29.6
390.10	STRUCTURES- MASONRY	35-R3	0	8,931,826	1,729,033	7,202,793	557,504	6.24	12.9
390.20	OPERATIONS BUILDINGS	35-R3	0	12,750,128	2,405,273	10,344,855	767,587	6.02	13.5
391.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	5,475,178	3,811,035	1,664,143	199,244	3.64	8.4
391.10	COMPUTER EQUIPMENT & SOFTWARE	10-SQ	0	31,957,542	20,400,688	11,556,854	1,599,848	5.01	7.2
391.20	PC COMPUTER EQUIPMENT & SOFTWARE	5-SQ	0	24,929,022	14,475,255	10,453,767	2,613,442	10.48	4.0
392.10	LIGHT DUTY VEHICLES	8-L3	20	6,766,552	186,391	5,226,851	1,266,432	18.72	4.1
392.20	HEAVY DUTY VEHICLES	20-L3	20	10,785,689	2,413,034	6,215,518	415,905	3.86	14.9
394.00	TOOLS AND WORK EQUIPMENT	15-SQ	0	10,869,029	6,546,629	4,322,400	438,361	4.03	9.9
397.00	COMMUNICATIONS STRUCTURES AND EQUIPMENT	15-SQ	0	22,698,403	7,165,405	15,532,998	1,827,007	8.05	8.5
	TOTAL GENERAL PLANT.			**135,500,733**	**59,399,439**	**72,590,846**	**9,687,714**	**7.15**	
	TOTAL DEPRECIABLE PLANT			**1,248,205,480**	**297,676,275**	**947,018,757**	**40,329,132**	**3.23**	
	PLANT NOT STUDIED								
114.00	UTILITY PLANT ACQUISITION ADJUSTMENT			11,912,000	4,839,225				
350.00	LAND RIGHTS			7,204,996					
360.00	LAND RIGHTS			2,456,724					
389.00	LAND			11,297,255	34,055				
390.90	LEASEHOLD IMPROVEMENTS			4,401,334	2,054,075				
	TOTAL NON - DEPRECIABLE PLANT			**37,272,309**	**6,927,355**				
	TOTAL PLANT			**1,285,477,789**	**304,603,630**	**947,018,757**	**40,329,132**		

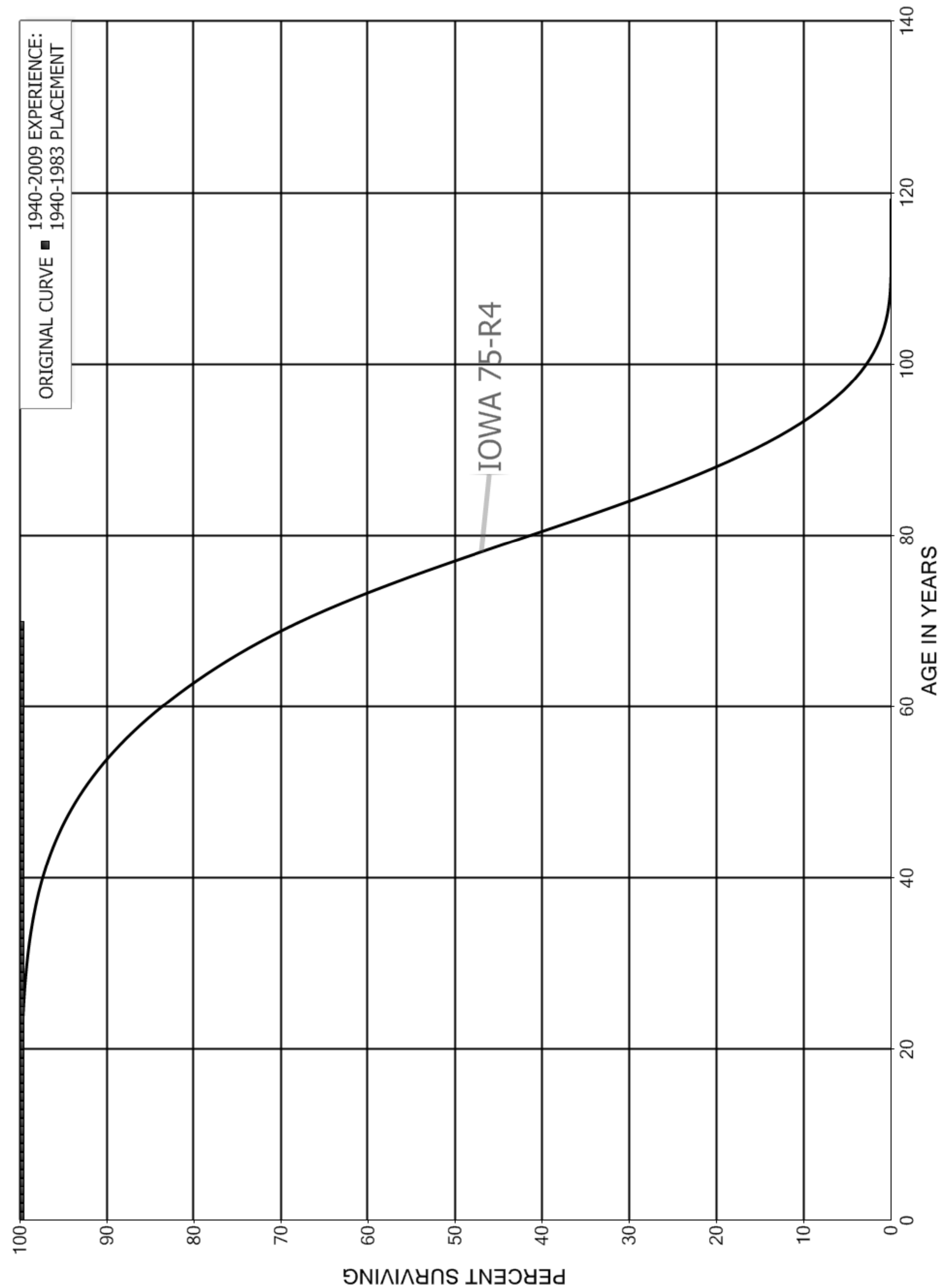
FORTISBC, INC.

SCHEDULE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009
DEPRECIATION RELATED TO RECOVERY OF COST OF REMOVAL

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE (%)	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GENERATION PLANT								
330.10	LAND RIGHTS	75-R4		961,358					
331.00	STRUCTURES AND IMPROVEMENTS	60-L3	(15)	12,015,310		1,802,297	38,184	0.32	47.2
332.00	RESERVOIRS, DAMS, AND WATERWAYS	70-R4	(15)	24,443,427		3,666,514	85,467	0.35	42.9
333.00	WATER WHEELS, TURBINES, AND GENERATORS	75-R3	(50)	61,382,405		30,691,202	642,075	1.05	47.8
334.00	ACCESSORY ELECTRICAL EQUIPMENT	50-R3	(30)	27,493,467		8,248,040	271,317	0.99	30.4
335.00	OTHER POWER PLANT EQUIPMENT	45-R4	(5)	40,893,990		2,044,700	58,925	0.14	34.7
336.00	ROADS, RAILROADS AND BRIDGES	75-S4		1,287,435					
	TOTAL GENERATION PLANT			**168,477,392**		**46,452,753**	**1,095,968**	**0.65**	
	TRANSMISSION PLANT								
350.10	LAND RIGHTS	75-R3		5,798,520					
353.00	SUBSTATION EQUIPMENT	50-S4	(30)	138,236,257		41,470,877	1,818,898	1.32	22.8
355.00	POLES, TOWERS AND FIXTURES	50-R3	(50)	72,712,210		36,356,105	1,262,365	1.74	28.8
356.00	CONDUCTORS AND DEVICES	60-R3	(50)	70,447,452		35,223,726	905,494	1.29	38.9
359.00	ROADS AND TRAILS	40-R0.5		1,121,930					
	TOTAL TRANSMISSION PLANT			**288,316,368**		**113,050,708**	**3,986,757**	**1.38**	
	DISTRIBUTION PLANT								
360.10	LAND RIGHTS	75-R3		8,477,101					
362.00	SUBSTATION EQUIPMENT	55-S3	(20)	181,230,662		36,246,132	969,148	0.53	37.4
364.00	POLES, TOWERS AND FIXTURES	50-R3	(40)	126,978,444		50,791,378	1,485,128	1.17	34.2
365.00	CONDUCTORS AND DEVICES	45-R3	(25)	208,986,680		52,246,670	1,759,147	0.84	29.7
368.00	LINE TRANSFORMERS	45-R4	(25)	98,456,668		24,614,167	1,000,576	1.02	24.6
369.00	SERVICES	75-R4		7,292,398					
370.00	METERS	20-R1		13,276,592					
371.00	INSTALLATIONS ON CUSTOMERS PREMISES	20-R1		937,832					
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	40-R4	(5)	10,274,609		513,730	138,846	1.35	3.7
	TOTAL DISTRIBUTION PLANT			**655,910,986**		**164,412,078**	**5,352,845**	**0.82**	
	GENERAL PLANT								
390.00	STRUCTURES - FRAME AND IRON	40-R3		337,364					
390.10	STRUCUTRES- MASONRY	35-R3		8,931,826					
390.20	OPERATIONS BUILDINGS	35-R3		12,750,128					
391.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ		5,475,178					
391.10	COMPUTER EQUIPMENT & SOFTWARE	10-SQ		31,957,542					
391.20	PC COMPUTER EQUIPMENT & SOFTWARE	5-SQ		24,929,022					
392.10	LIGHT DUTY VEHICLES	8-L3	20	6,766,552					
392.20	HEAVY DUTY VEHICLES	20-L3	20	10,785,689					
394.00	TOOLS AND WORK EQUIPMENT	15-SQ		10,869,029					
397.00	COMMUNICATIONS STRUCTURES AND EQUIPMENT	15-SQ		22,698,403					
	TOTAL GENERAL PLANT.			**135,500,733**					
	TOTAL DEPRECIABLE PLANT			**1,248,205,480**		**323,915,538**	**10,435,570**	**0.84**	
	PLANT NOT STUDIED								
114.00	UTILITY PLANT ACQUISITION ADJUSTMENT			11,912,000					
350.00	LAND RIGHTS			7,204,996					
360.00	LAND RIGHTS			2,456,724					
389.00	LAND			11,297,255					
390.90	LEASEHOLD IMPROVEMENTS			4,401,334					
	TOTAL NON - DEPRECIABLE PLANT			**37,272,309**					
	TOTAL PLANT			**1,285,477,789**		**323,915,538**	**10,442,253**		

PART IV. SERVICE LIFE STATISTICS

FORTISBC, INC.
ACCOUNT 330.10 - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 330.10 - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-1983 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	961,358		0.0000	1.0000	100.00
0.5	961,358		0.0000	1.0000	100.00
1.5	961,358		0.0000	1.0000	100.00
2.5	961,358		0.0000	1.0000	100.00
3.5	961,358		0.0000	1.0000	100.00
4.5	961,358		0.0000	1.0000	100.00
5.5	961,358		0.0000	1.0000	100.00
6.5	961,358		0.0000	1.0000	100.00
7.5	961,358		0.0000	1.0000	100.00
8.5	961,358		0.0000	1.0000	100.00
9.5	961,358		0.0000	1.0000	100.00
10.5	961,358		0.0000	1.0000	100.00
11.5	961,358		0.0000	1.0000	100.00
12.5	961,358		0.0000	1.0000	100.00
13.5	961,358		0.0000	1.0000	100.00
14.5	961,358		0.0000	1.0000	100.00
15.5	961,358		0.0000	1.0000	100.00
16.5	961,358		0.0000	1.0000	100.00
17.5	961,358		0.0000	1.0000	100.00
18.5	961,358		0.0000	1.0000	100.00
19.5	961,358		0.0000	1.0000	100.00
20.5	961,358		0.0000	1.0000	100.00
21.5	961,358		0.0000	1.0000	100.00
22.5	961,358		0.0000	1.0000	100.00
23.5	961,358		0.0000	1.0000	100.00
24.5	961,358		0.0000	1.0000	100.00
25.5	961,358		0.0000	1.0000	100.00
26.5	98,939		0.0000	1.0000	100.00
27.5	15,998		0.0000	1.0000	100.00
28.5	15,998		0.0000	1.0000	100.00
29.5	15,998		0.0000	1.0000	100.00
30.5	15,998		0.0000	1.0000	100.00
31.5	15,998		0.0000	1.0000	100.00
32.5	15,998		0.0000	1.0000	100.00
33.5	15,998		0.0000	1.0000	100.00
34.5	15,998		0.0000	1.0000	100.00
35.5	15,998		0.0000	1.0000	100.00
36.5	15,998		0.0000	1.0000	100.00
37.5	15,998		0.0000	1.0000	100.00
38.5	15,998		0.0000	1.0000	100.00

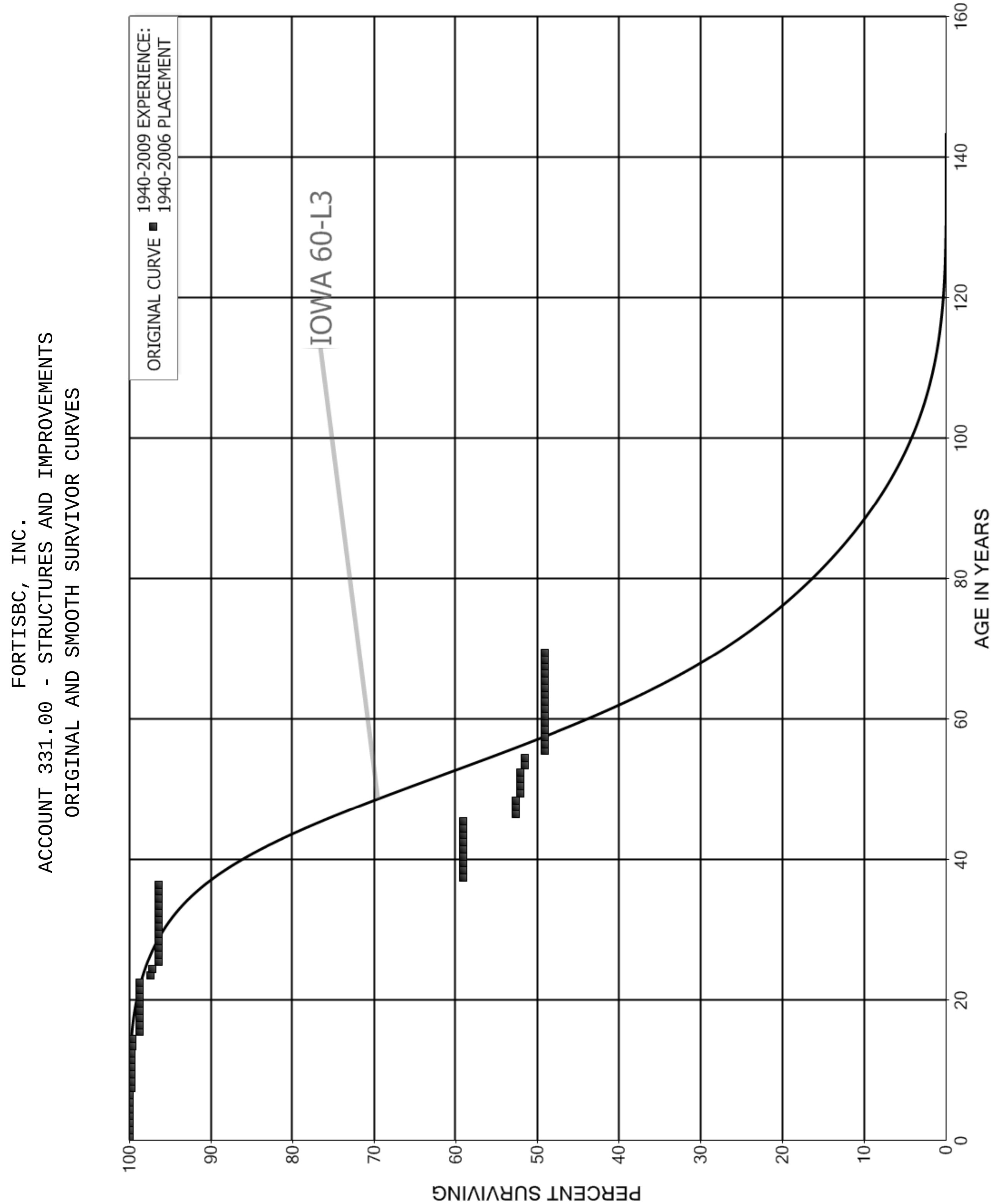
FORTISBC, INC.

ACCOUNT 330.10 - LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-1983 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	15,998		0.0000	1.0000	100.00
40.5	15,998		0.0000	1.0000	100.00
41.5	15,998		0.0000	1.0000	100.00
42.5	15,998		0.0000	1.0000	100.00
43.5	15,998		0.0000	1.0000	100.00
44.5	15,998		0.0000	1.0000	100.00
45.5	15,998		0.0000	1.0000	100.00
46.5	15,998		0.0000	1.0000	100.00
47.5	15,998		0.0000	1.0000	100.00
48.5	15,998		0.0000	1.0000	100.00
49.5	15,998		0.0000	1.0000	100.00
50.5	15,998		0.0000	1.0000	100.00
51.5	15,998		0.0000	1.0000	100.00
52.5	15,998		0.0000	1.0000	100.00
53.5	15,998		0.0000	1.0000	100.00
54.5	15,998		0.0000	1.0000	100.00
55.5	15,998		0.0000	1.0000	100.00
56.5	15,998		0.0000	1.0000	100.00
57.5	15,998		0.0000	1.0000	100.00
58.5	15,998		0.0000	1.0000	100.00
59.5	15,998		0.0000	1.0000	100.00
60.5	15,998		0.0000	1.0000	100.00
61.5	15,998		0.0000	1.0000	100.00
62.5	15,998		0.0000	1.0000	100.00
63.5	15,998		0.0000	1.0000	100.00
64.5	15,998		0.0000	1.0000	100.00
65.5	15,998		0.0000	1.0000	100.00
66.5	15,998		0.0000	1.0000	100.00
67.5	15,998		0.0000	1.0000	100.00
68.5	15,998		0.0000	1.0000	100.00
69.5					100.00


FORTISBC, INC.
ACCOUNT 331.00 - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1940-2009 EXPERIENCE:
1940-2006 PLACEMENT
IOWA 60-L3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120
140
160

FORTISBC, INC.

ACCOUNT 331.00 - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2006 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,410,509	22	0.0000	1.0000	100.00
0.5	12,410,487	3	0.0000	1.0000	100.00
1.5	12,410,483	24	0.0000	1.0000	100.00
2.5	12,410,459	2	0.0000	1.0000	100.00
3.5	12,410,456	13	0.0000	1.0000	100.00
4.5	12,410,442	2	0.0000	1.0000	100.00
5.5	12,235,746	12,150	0.0010	0.9990	100.00
6.5	11,647,414	24,726	0.0021	0.9979	99.90
7.5	11,237,542	2	0.0000	1.0000	99.69
8.5	10,254,541	6	0.0000	1.0000	99.69
9.5	9,084,961	6	0.0000	1.0000	99.69
10.5	8,999,993	16	0.0000	1.0000	99.69
11.5	6,029,362		0.0000	1.0000	99.69
12.5	5,935,161	4,122	0.0007	0.9993	99.69
13.5	5,783,643		0.0000	1.0000	99.62
14.5	3,595,240	31,200	0.0087	0.9913	99.62
15.5	3,390,404		0.0000	1.0000	98.75
16.5	2,254,094		0.0000	1.0000	98.75
17.5	2,254,094		0.0000	1.0000	98.75
18.5	2,254,094		0.0000	1.0000	98.75
19.5	1,491,541		0.0000	1.0000	98.75
20.5	1,491,541		0.0000	1.0000	98.75
21.5	1,491,541		0.0000	1.0000	98.75
22.5	1,491,541	20,654	0.0138	0.9862	98.75
23.5	1,417,548	3,832	0.0027	0.9973	97.39
24.5	1,364,476	10,530	0.0077	0.9923	97.12
25.5	1,350,311		0.0000	1.0000	96.37
26.5	1,350,311		0.0000	1.0000	96.37
27.5	586,555		0.0000	1.0000	96.37
28.5	586,555		0.0000	1.0000	96.37
29.5	586,555		0.0000	1.0000	96.37
30.5	586,555		0.0000	1.0000	96.37
31.5	586,555		0.0000	1.0000	96.37
32.5	586,555		0.0000	1.0000	96.37
33.5	586,555		0.0000	1.0000	96.37
34.5	586,555		0.0000	1.0000	96.37
35.5	586,555		0.0000	1.0000	96.37
36.5	586,555	227,314	0.3875	0.6125	96.37
37.5	359,241		0.0000	1.0000	59.02
38.5	359,241		0.0000	1.0000	59.02

FORTISBC, INC.

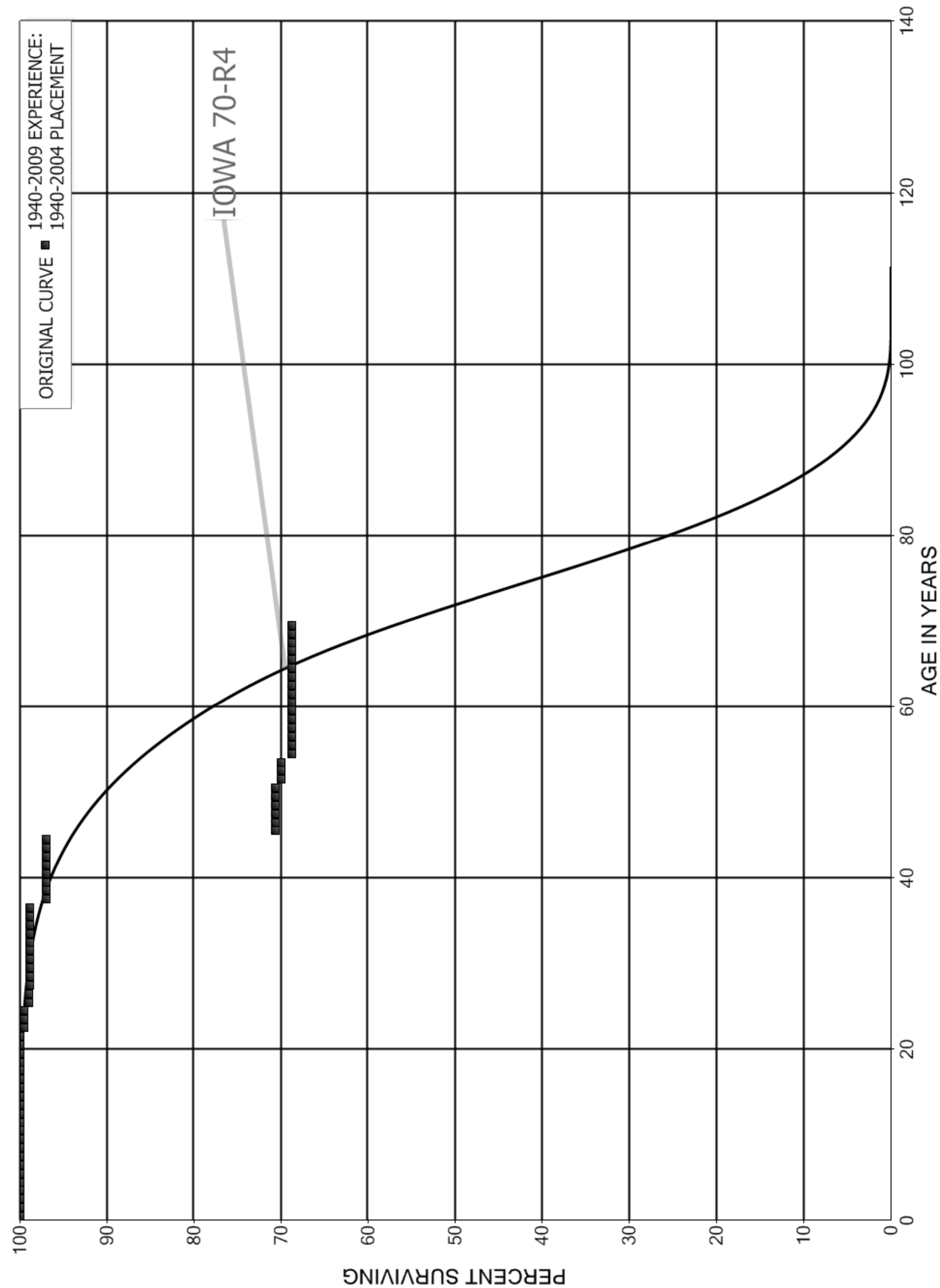
ACCOUNT 331.00 - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2006 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	359,241		0.0000	1.0000	59.02
40.5	359,241		0.0000	1.0000	59.02
41.5	359,241		0.0000	1.0000	59.02
42.5	359,241		0.0000	1.0000	59.02
43.5	359,241		0.0000	1.0000	59.02
44.5	359,241		0.0000	1.0000	59.02
45.5	359,241	39,309	0.1094	0.8906	59.02
46.5	319,932		0.0000	1.0000	52.57
47.5	319,932		0.0000	1.0000	52.57
48.5	319,932	2,935	0.0092	0.9908	52.57
49.5	316,997		0.0000	1.0000	52.08
50.5	316,997		0.0000	1.0000	52.08
51.5	316,997		0.0000	1.0000	52.08
52.5	316,997	3,653	0.0115	0.9885	52.08
53.5	313,344		0.0000	1.0000	51.48
54.5	313,344	14,675	0.0468	0.9532	51.48
55.5	298,669		0.0000	1.0000	49.07
56.5	298,669		0.0000	1.0000	49.07
57.5	298,669		0.0000	1.0000	49.07
58.5	298,669		0.0000	1.0000	49.07
59.5	298,669		0.0000	1.0000	49.07
60.5	298,669		0.0000	1.0000	49.07
61.5	298,669		0.0000	1.0000	49.07
62.5	298,669		0.0000	1.0000	49.07
63.5	298,669		0.0000	1.0000	49.07
64.5	298,669		0.0000	1.0000	49.07
65.5	298,669		0.0000	1.0000	49.07
66.5	298,669		0.0000	1.0000	49.07
67.5	298,669		0.0000	1.0000	49.07
68.5	298,669		0.0000	1.0000	49.07
69.5					49.07

FORTISBC, INC.
ACCOUNT 332.00 - RESERVOIRS, DAMS, AND WATERWAYS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 332.00 - RESERVOIRS, DAMS, AND WATERWAYS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2004 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,040,208	235	0.0000	1.0000	100.00
0.5	25,039,973	218	0.0000	1.0000	100.00
1.5	25,039,755	215	0.0000	1.0000	100.00
2.5	25,039,540	333	0.0000	1.0000	100.00
3.5	25,039,207	116	0.0000	1.0000	100.00
4.5	25,039,090	124	0.0000	1.0000	100.00
5.5	23,934,727	93	0.0000	1.0000	100.00
6.5	23,087,090	111	0.0000	1.0000	99.99
7.5	23,086,979	752	0.0000	1.0000	99.99
8.5	23,086,227	2,827	0.0001	0.9999	99.99
9.5	22,383,650	5	0.0000	1.0000	99.98
10.5	22,383,645		0.0000	1.0000	99.98
11.5	22,383,645	4,752	0.0002	0.9998	99.98
12.5	22,357,216		0.0000	1.0000	99.96
13.5	22,344,138	2	0.0000	1.0000	99.96
14.5	22,344,136		0.0000	1.0000	99.96
15.5	21,108,273		0.0000	1.0000	99.96
16.5	18,124,124	4	0.0000	1.0000	99.96
17.5	17,651,789		0.0000	1.0000	99.96
18.5	16,694,527		0.0000	1.0000	99.96
19.5	16,536,952		0.0000	1.0000	99.96
20.5	16,211,071		0.0000	1.0000	99.96
21.5	15,975,684	68,452	0.0043	0.9957	99.96
22.5	15,661,023	2,102	0.0001	0.9999	99.53
23.5	15,637,547	3,015	0.0002	0.9998	99.52
24.5	15,634,532	83,507	0.0053	0.9947	99.50
25.5	15,542,728		0.0000	1.0000	98.97
26.5	15,542,728	19,693	0.0013	0.9987	98.97
27.5	1,356,312		0.0000	1.0000	98.84
28.5	1,356,312		0.0000	1.0000	98.84
29.5	1,356,312		0.0000	1.0000	98.84
30.5	1,356,312		0.0000	1.0000	98.84
31.5	1,356,312		0.0000	1.0000	98.84
32.5	1,352,574		0.0000	1.0000	98.84
33.5	1,352,574		0.0000	1.0000	98.84
34.5	1,352,574		0.0000	1.0000	98.84
35.5	1,352,574		0.0000	1.0000	98.84
36.5	1,352,574	26,222	0.0194	0.9806	98.84
37.5	1,326,352		0.0000	1.0000	96.92
38.5	1,326,352		0.0000	1.0000	96.92

FORTISBC, INC.

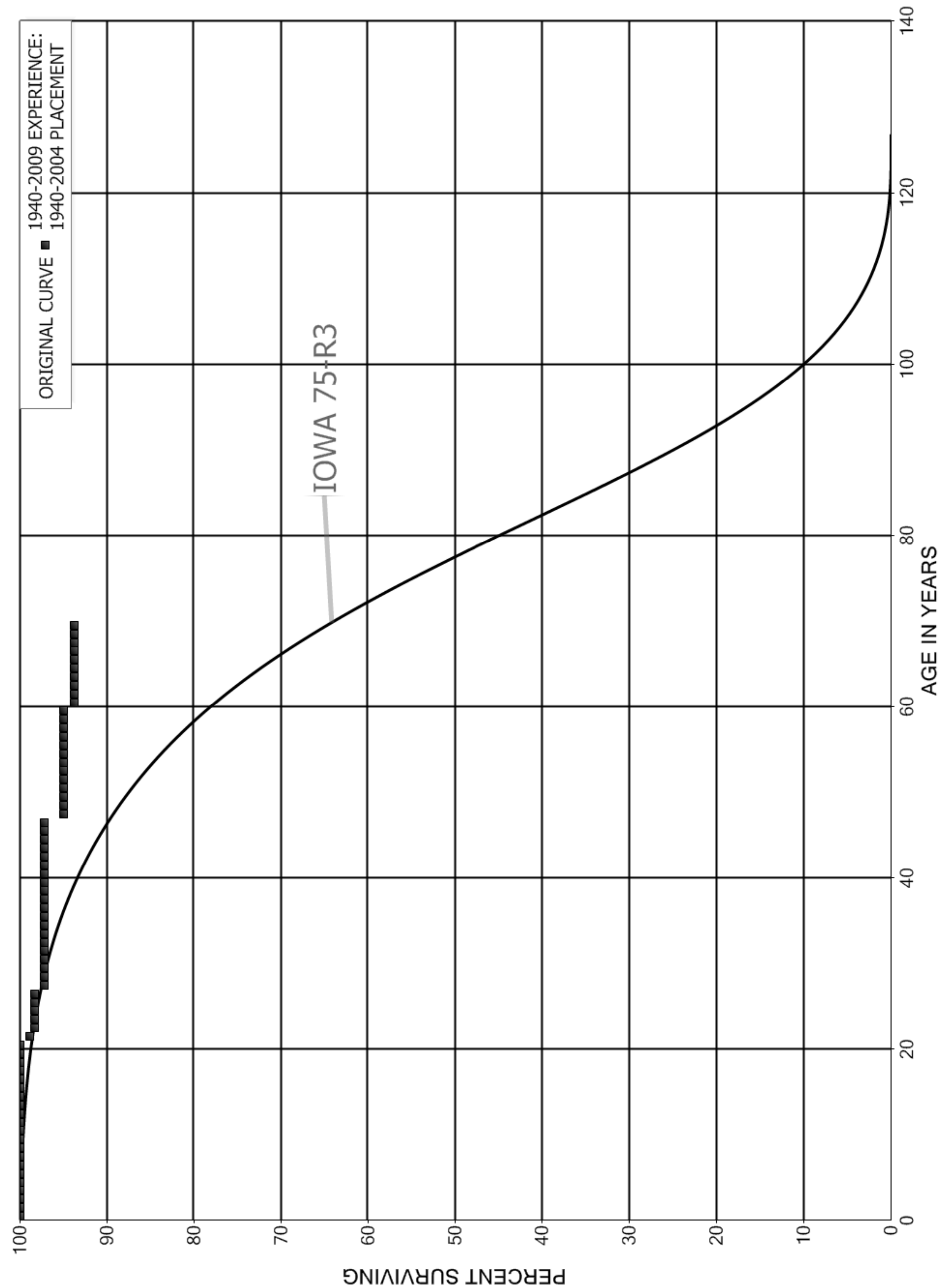
ACCOUNT 332.00 - RESERVOIRS, DAMS, AND WATERWAYS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2004 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,326,352		0.0000	1.0000	96.92
40.5	1,326,352		0.0000	1.0000	96.92
41.5	1,326,352		0.0000	1.0000	96.92
42.5	1,326,352		0.0000	1.0000	96.92
43.5	1,326,352		0.0000	1.0000	96.92
44.5	1,326,352	359,807	0.2713	0.7287	96.92
45.5	966,545		0.0000	1.0000	70.63
46.5	966,545		0.0000	1.0000	70.63
47.5	966,545		0.0000	1.0000	70.63
48.5	966,545	698	0.0007	0.9993	70.63
49.5	881,443		0.0000	1.0000	70.58
50.5	881,443	8,068	0.0092	0.9908	70.58
51.5	873,375		0.0000	1.0000	69.93
52.5	873,375		0.0000	1.0000	69.93
53.5	873,375	15,430	0.0177	0.9823	69.93
54.5	857,945		0.0000	1.0000	68.70
55.5	857,945		0.0000	1.0000	68.70
56.5	857,945		0.0000	1.0000	68.70
57.5	857,945		0.0000	1.0000	68.70
58.5	857,945		0.0000	1.0000	68.70
59.5	857,945		0.0000	1.0000	68.70
60.5	857,945		0.0000	1.0000	68.70
61.5	857,945		0.0000	1.0000	68.70
62.5	857,945		0.0000	1.0000	68.70
63.5	857,945		0.0000	1.0000	68.70
64.5	857,945		0.0000	1.0000	68.70
65.5	857,945		0.0000	1.0000	68.70
66.5	857,945		0.0000	1.0000	68.70
67.5	857,945		0.0000	1.0000	68.70
68.5	857,945		0.0000	1.0000	68.70
69.5					68.70

FORTISBC, INC.
ACCOUNT 333.00 - WATER WHEELS, TURBINES, AND GENERATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



IV-11

FORTISBC, INC.

ACCOUNT 333.00 - WATER WHEELS, TURBINES, AND GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2004 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	62,697,338	1,847	0.0000	1.0000	100.00
0.5	62,695,491	146	0.0000	1.0000	100.00
1.5	62,695,345	5,712	0.0001	0.9999	100.00
2.5	62,689,633	215	0.0000	1.0000	99.99
3.5	62,689,417	564	0.0000	1.0000	99.99
4.5	62,688,853	350	0.0000	1.0000	99.99
5.5	48,891,933	202	0.0000	1.0000	99.99
6.5	48,780,544	78	0.0000	1.0000	99.99
7.5	48,613,305		0.0000	1.0000	99.99
8.5	41,830,187		0.0000	1.0000	99.99
9.5	38,537,495	77	0.0000	1.0000	99.99
10.5	38,412,481		0.0000	1.0000	99.99
11.5	33,637,372		0.0000	1.0000	99.99
12.5	33,465,021	16	0.0000	1.0000	99.99
13.5	33,031,807	84	0.0000	1.0000	99.99
14.5	32,773,765	34	0.0000	1.0000	99.98
15.5	32,630,160	112	0.0000	1.0000	99.98
16.5	32,576,869		0.0000	1.0000	99.98
17.5	32,576,869	12,573	0.0004	0.9996	99.98
18.5	32,564,297		0.0000	1.0000	99.95
19.5	32,517,792		0.0000	1.0000	99.95
20.5	32,517,792	362,137	0.0111	0.9889	99.95
21.5	32,155,654	166,625	0.0052	0.9948	98.83
22.5	31,980,348		0.0000	1.0000	98.32
23.5	31,936,684	729	0.0000	1.0000	98.32
24.5	31,918,854		0.0000	1.0000	98.32
25.5	31,865,135		0.0000	1.0000	98.32
26.5	31,865,135	355,334	0.0112	0.9888	98.32
27.5	16,605,071		0.0000	1.0000	97.22
28.5	16,605,071		0.0000	1.0000	97.22
29.5	16,605,071		0.0000	1.0000	97.22
30.5	16,603,448		0.0000	1.0000	97.22
31.5	16,603,448		0.0000	1.0000	97.22
32.5	16,603,448		0.0000	1.0000	97.22
33.5	16,603,448		0.0000	1.0000	97.22
34.5	16,603,448		0.0000	1.0000	97.22
35.5	16,603,448		0.0000	1.0000	97.22
36.5	16,603,448		0.0000	1.0000	97.22
37.5	16,603,448		0.0000	1.0000	97.22
38.5	16,603,448	4,196	0.0003	0.9997	97.22

FORTISBC, INC.

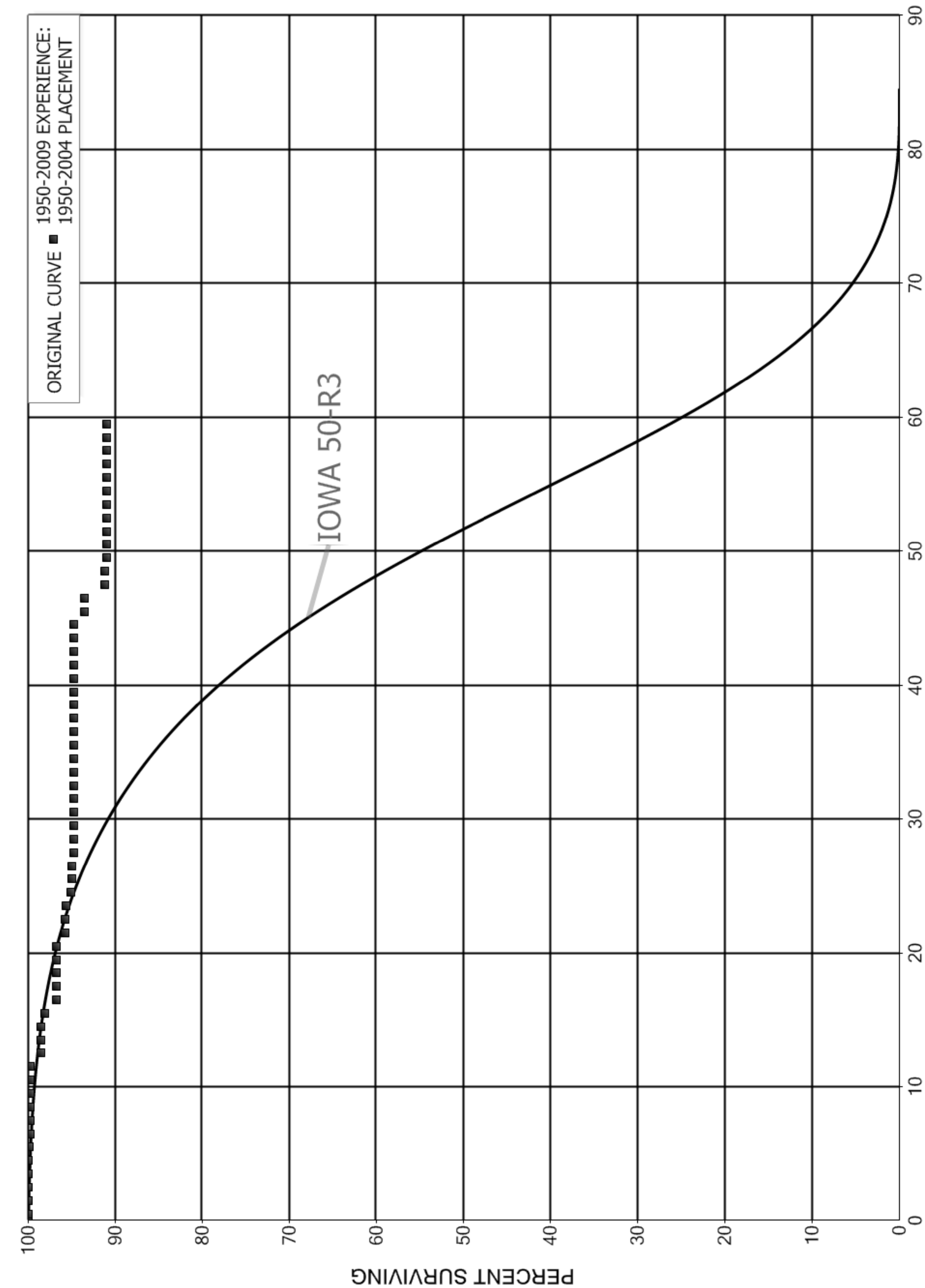
ACCOUNT 333.00 - WATER WHEELS, TURBINES, AND GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2004 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,599,252	11,818	0.0007	0.9993	97.20
40.5	16,587,435		0.0000	1.0000	97.13
41.5	16,587,435		0.0000	1.0000	97.13
42.5	16,587,435		0.0000	1.0000	97.13
43.5	16,587,435		0.0000	1.0000	97.13
44.5	16,587,435		0.0000	1.0000	97.13
45.5	16,587,435	355	0.0000	1.0000	97.13
46.5	16,587,080	367,027	0.0221	0.9779	97.13
47.5	16,220,053		0.0000	1.0000	94.98
48.5	16,220,053	13,147	0.0008	0.9992	94.98
49.5	904,696		0.0000	1.0000	94.90
50.5	904,696		0.0000	1.0000	94.90
51.5	904,696		0.0000	1.0000	94.90
52.5	904,696		0.0000	1.0000	94.90
53.5	904,696		0.0000	1.0000	94.90
54.5	904,696		0.0000	1.0000	94.90
55.5	904,696		0.0000	1.0000	94.90
56.5	904,696		0.0000	1.0000	94.90
57.5	904,696		0.0000	1.0000	94.90
58.5	904,696		0.0000	1.0000	94.90
59.5	904,696	11,555	0.0128	0.9872	94.90
60.5	893,140		0.0000	1.0000	93.69
61.5	893,140		0.0000	1.0000	93.69
62.5	893,140		0.0000	1.0000	93.69
63.5	893,140		0.0000	1.0000	93.69
64.5	893,140		0.0000	1.0000	93.69
65.5	893,140		0.0000	1.0000	93.69
66.5	893,140		0.0000	1.0000	93.69
67.5	893,140		0.0000	1.0000	93.69
68.5	893,140		0.0000	1.0000	93.69
69.5					93.69

FORTISBC, INC.
ACCOUNT 334.00 - ACCESSORY ELECTRICAL EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 334.00 - ACCESSORY ELECTRICAL EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1950-2004 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,194,492	1	0.0000	1.0000	100.00
0.5	28,194,492	2	0.0000	1.0000	100.00
1.5	28,194,489		0.0000	1.0000	100.00
2.5	28,194,489	28,650	0.0010	0.9990	100.00
3.5	28,165,839		0.0000	1.0000	99.90
4.5	28,165,839	21,670	0.0008	0.9992	99.90
5.5	22,885,086	16,800	0.0007	0.9993	99.82
6.5	22,671,969	300	0.0000	1.0000	99.75
7.5	21,662,594	6	0.0000	1.0000	99.75
8.5	18,258,959		0.0000	1.0000	99.75
9.5	13,865,266	4	0.0000	1.0000	99.75
10.5	13,658,103		0.0000	1.0000	99.75
11.5	13,102,112	170,267	0.0130	0.9870	99.75
12.5	7,823,139		0.0000	1.0000	98.45
13.5	7,352,756		0.0000	1.0000	98.45
14.5	6,943,660	27,435	0.0040	0.9960	98.45
15.5	6,813,239	94,037	0.0138	0.9862	98.06
16.5	6,505,918	1	0.0000	1.0000	96.71
17.5	6,505,918	2	0.0000	1.0000	96.71
18.5	6,505,916	1	0.0000	1.0000	96.71
19.5	6,505,915		0.0000	1.0000	96.71
20.5	6,505,915	69,044	0.0106	0.9894	96.71
21.5	6,436,871		0.0000	1.0000	95.68
22.5	6,436,871	5,469	0.0008	0.9992	95.68
23.5	6,280,675	37,818	0.0060	0.9940	95.60
24.5	6,242,856	5,865	0.0009	0.9991	95.02
25.5	6,157,103		0.0000	1.0000	94.94
26.5	6,157,103	11,866	0.0019	0.9981	94.94
27.5	5,285,547		0.0000	1.0000	94.75
28.5	5,285,547		0.0000	1.0000	94.75
29.5	5,285,547		0.0000	1.0000	94.75
30.5	5,285,547		0.0000	1.0000	94.75
31.5	5,273,364		0.0000	1.0000	94.75
32.5	5,268,983		0.0000	1.0000	94.75
33.5	5,259,200		0.0000	1.0000	94.75
34.5	5,252,965		0.0000	1.0000	94.75
35.5	5,252,965		0.0000	1.0000	94.75
36.5	5,252,965		0.0000	1.0000	94.75
37.5	5,252,965		0.0000	1.0000	94.75
38.5	5,252,965		0.0000	1.0000	94.75

FORTISBC, INC.

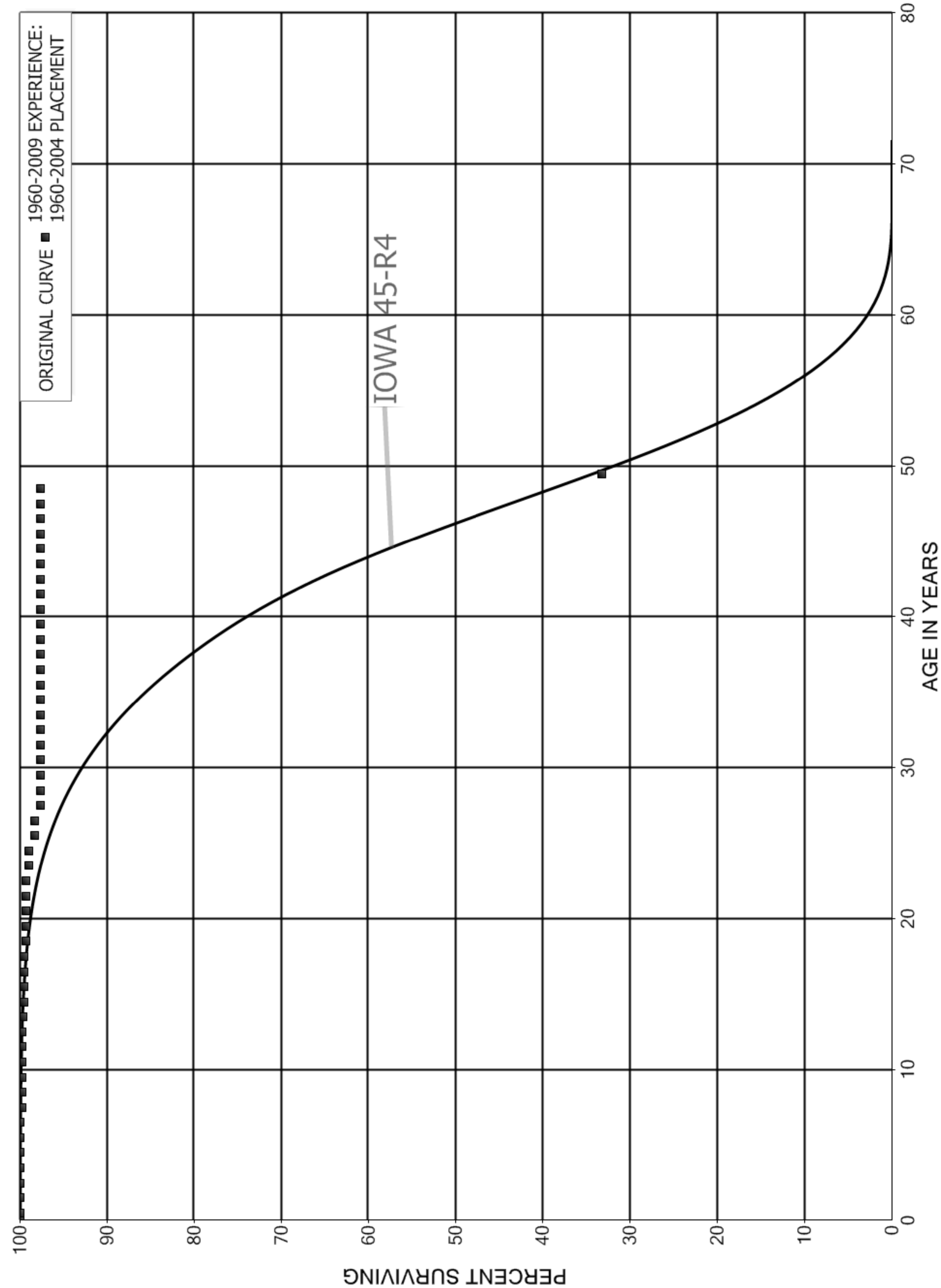
ACCOUNT 334.00 - ACCESSORY ELECTRICAL EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1950-2004 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,252,965		0.0000	1.0000	94.75
40.5	5,252,965		0.0000	1.0000	94.75
41.5	5,252,965		0.0000	1.0000	94.75
42.5	5,252,965		0.0000	1.0000	94.75
43.5	5,252,965	1,947	0.0004	0.9996	94.75
44.5	5,251,017	64,694	0.0123	0.9877	94.72
45.5	5,186,323		0.0000	1.0000	93.55
46.5	5,186,323	132,922	0.0256	0.9744	93.55
47.5	5,053,401		0.0000	1.0000	91.15
48.5	5,053,401	12,223	0.0024	0.9976	91.15
49.5	493,652		0.0000	1.0000	90.93
50.5	493,652		0.0000	1.0000	90.93
51.5	493,652		0.0000	1.0000	90.93
52.5	493,652		0.0000	1.0000	90.93
53.5	493,652		0.0000	1.0000	90.93
54.5	493,652		0.0000	1.0000	90.93
55.5	493,652		0.0000	1.0000	90.93
56.5	493,652		0.0000	1.0000	90.93
57.5	493,652		0.0000	1.0000	90.93
58.5	493,652		0.0000	1.0000	90.93
59.5					90.93

FORTISBC, INC.
ACCOUNT 335.00 - OTHER POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 335.00 - OTHER POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2004 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	41,127,153	3,037	0.0001	0.9999	100.00
0.5	41,124,116	3,192	0.0001	0.9999	99.99
1.5	41,120,924	6,995	0.0002	0.9998	99.98
2.5	41,113,929	8,763	0.0002	0.9998	99.97
3.5	41,105,166	5,976	0.0001	0.9999	99.95
4.5	41,099,191	1,783	0.0000	1.0000	99.93
5.5	30,694,070	2,528	0.0001	0.9999	99.93
6.5	12,452,934	20,037	0.0016	0.9984	99.92
7.5	11,937,787	273	0.0000	1.0000	99.76
8.5	11,227,427	1,313	0.0001	0.9999	99.76
9.5	10,288,278	3,603	0.0004	0.9996	99.74
10.5	9,576,469	3,149	0.0003	0.9997	99.71
11.5	8,294,057		0.0000	1.0000	99.68
12.5	7,942,693	1,020	0.0001	0.9999	99.68
13.5	7,558,975	9,472	0.0013	0.9987	99.66
14.5	7,470,216	2,257	0.0003	0.9997	99.54
15.5	7,159,045	1,520	0.0002	0.9998	99.51
16.5	6,777,934		0.0000	1.0000	99.49
17.5	6,499,640	15,786	0.0024	0.9976	99.49
18.5	6,380,526		0.0000	1.0000	99.25
19.5	6,089,354		0.0000	1.0000	99.25
20.5	5,978,682		0.0000	1.0000	99.25
21.5	5,978,682		0.0000	1.0000	99.25
22.5	5,920,043	20,946	0.0035	0.9965	99.25
23.5	5,412,859		0.0000	1.0000	98.90
24.5	5,309,444	30,528	0.0057	0.9943	98.90
25.5	5,216,700		0.0000	1.0000	98.33
26.5	5,216,700	35,514	0.0068	0.9932	98.33
27.5	84,069		0.0000	1.0000	97.66
28.5	84,069		0.0000	1.0000	97.66
29.5	84,069		0.0000	1.0000	97.66
30.5	84,069		0.0000	1.0000	97.66
31.5	84,069		0.0000	1.0000	97.66
32.5	84,069		0.0000	1.0000	97.66
33.5	84,069		0.0000	1.0000	97.66
34.5	84,069		0.0000	1.0000	97.66
35.5	84,069		0.0000	1.0000	97.66
36.5	84,069		0.0000	1.0000	97.66
37.5	84,069		0.0000	1.0000	97.66
38.5	84,069		0.0000	1.0000	97.66

FORTISBC, INC.

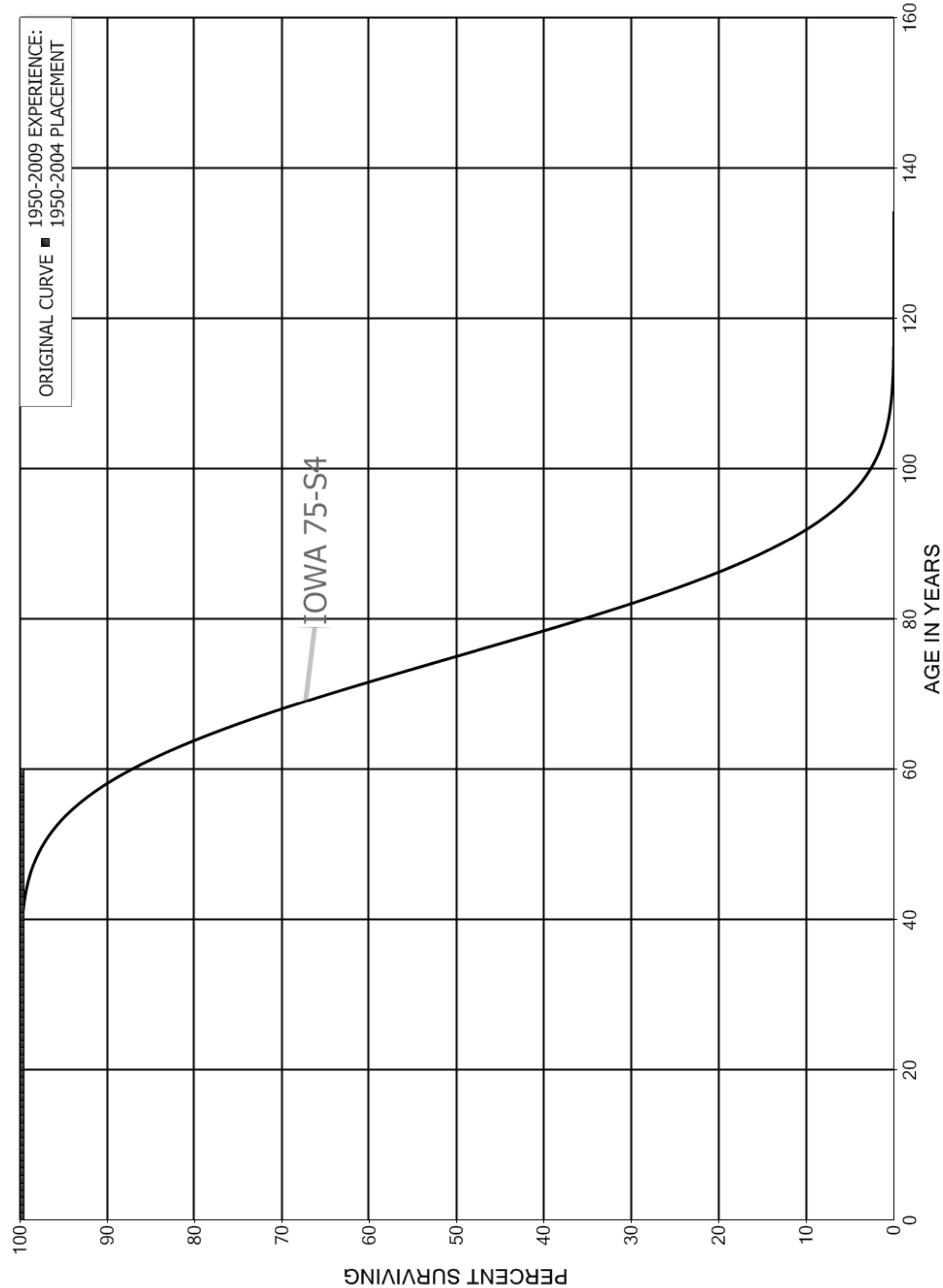
ACCOUNT 335.00 - OTHER POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2004 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	84,069		0.0000	1.0000	97.66
40.5	84,069		0.0000	1.0000	97.66
41.5	84,069		0.0000	1.0000	97.66
42.5	84,069		0.0000	1.0000	97.66
43.5	84,069		0.0000	1.0000	97.66
44.5	84,069		0.0000	1.0000	97.66
45.5	84,069		0.0000	1.0000	97.66
46.5	84,069		0.0000	1.0000	97.66
47.5	84,069		0.0000	1.0000	97.66
48.5	84,069	55,471	0.6598	0.3402	97.66
49.5					33.22

FORTISBC, INC.
ACCOUNT 336.00 - ROADS, RAILROADS AND BRIDGES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 336.00 - ROADS, RAILROADS AND BRIDGES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1950-2004 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,287,435		0.0000	1.0000	100.00
0.5	1,287,435		0.0000	1.0000	100.00
1.5	1,287,435		0.0000	1.0000	100.00
2.5	1,287,435		0.0000	1.0000	100.00
3.5	1,287,435		0.0000	1.0000	100.00
4.5	1,287,435		0.0000	1.0000	100.00
5.5	1,286,516		0.0000	1.0000	100.00
6.5	1,272,082		0.0000	1.0000	100.00
7.5	1,259,996		0.0000	1.0000	100.00
8.5	1,258,598		0.0000	1.0000	100.00
9.5	1,227,140		0.0000	1.0000	100.00
10.5	693,082		0.0000	1.0000	100.00
11.5	693,082		0.0000	1.0000	100.00
12.5	693,082		0.0000	1.0000	100.00
13.5	693,082		0.0000	1.0000	100.00
14.5	693,082		0.0000	1.0000	100.00
15.5	693,082		0.0000	1.0000	100.00
16.5	693,082		0.0000	1.0000	100.00
17.5	693,082		0.0000	1.0000	100.00
18.5	693,082		0.0000	1.0000	100.00
19.5	693,082		0.0000	1.0000	100.00
20.5	693,082		0.0000	1.0000	100.00
21.5	693,082		0.0000	1.0000	100.00
22.5	693,082		0.0000	1.0000	100.00
23.5	693,082		0.0000	1.0000	100.00
24.5	693,082		0.0000	1.0000	100.00
25.5	675,244		0.0000	1.0000	100.00
26.5	675,244		0.0000	1.0000	100.00
27.5	2,712		0.0000	1.0000	100.00
28.5	2,712		0.0000	1.0000	100.00
29.5	2,712		0.0000	1.0000	100.00
30.5	2,712		0.0000	1.0000	100.00
31.5	2,712		0.0000	1.0000	100.00
32.5	2,712		0.0000	1.0000	100.00
33.5	2,712		0.0000	1.0000	100.00
34.5	2,712		0.0000	1.0000	100.00
35.5	2,712		0.0000	1.0000	100.00
36.5	2,712		0.0000	1.0000	100.00
37.5	2,712		0.0000	1.0000	100.00
38.5	2,712		0.0000	1.0000	100.00

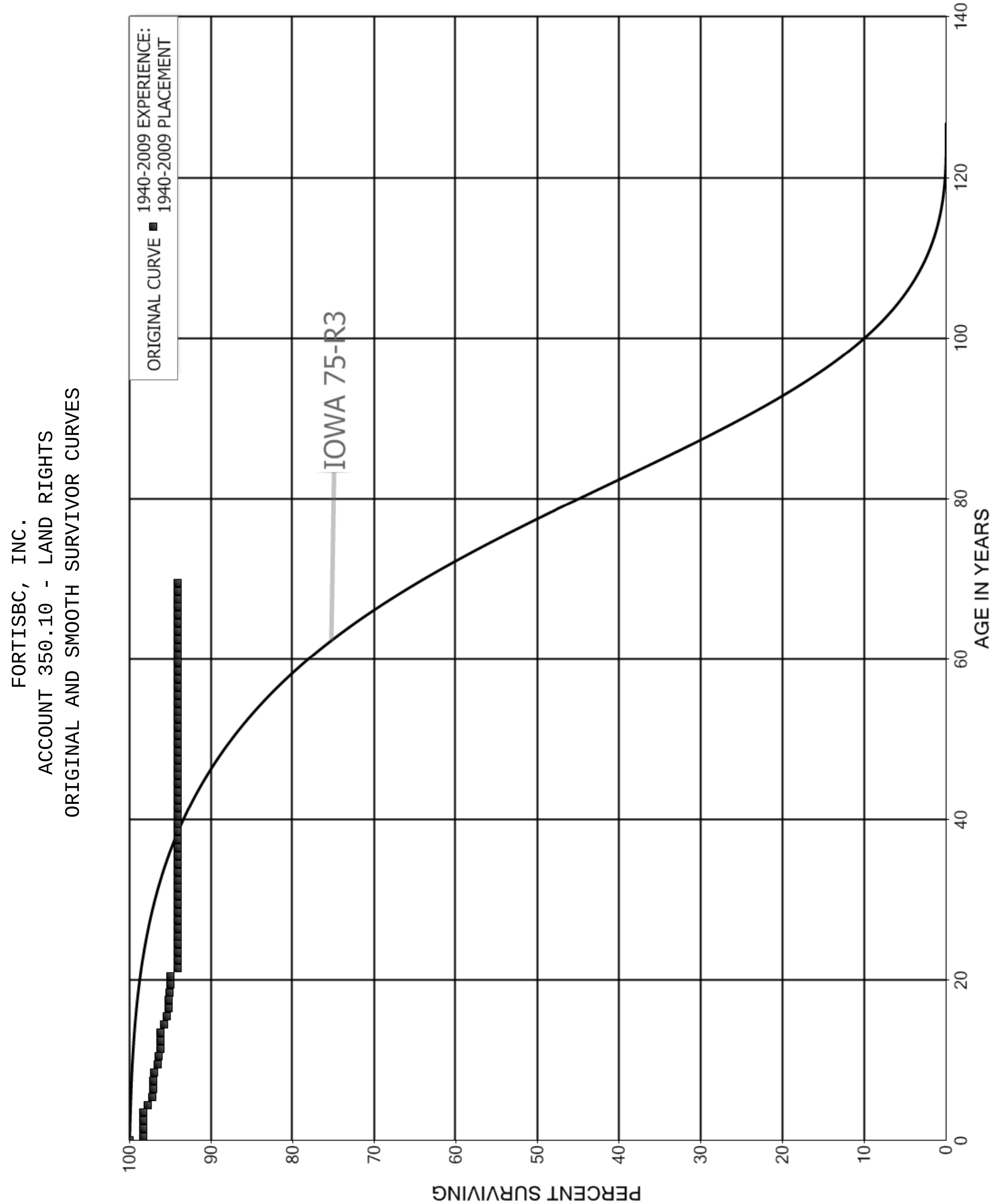
FORTISBC, INC.

ACCOUNT 336.00 - ROADS, RAILROADS AND BRIDGES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1950-2004 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,712		0.0000	1.0000	100.00
40.5	2,712		0.0000	1.0000	100.00
41.5	2,712		0.0000	1.0000	100.00
42.5	2,712		0.0000	1.0000	100.00
43.5	2,712		0.0000	1.0000	100.00
44.5	2,712		0.0000	1.0000	100.00
45.5	2,712		0.0000	1.0000	100.00
46.5	2,712		0.0000	1.0000	100.00
47.5	2,712		0.0000	1.0000	100.00
48.5	2,712		0.0000	1.0000	100.00
49.5	2,712		0.0000	1.0000	100.00
50.5	2,712		0.0000	1.0000	100.00
51.5	2,712		0.0000	1.0000	100.00
52.5	2,712		0.0000	1.0000	100.00
53.5	2,712		0.0000	1.0000	100.00
54.5	2,712		0.0000	1.0000	100.00
55.5	2,712		0.0000	1.0000	100.00
56.5	2,712		0.0000	1.0000	100.00
57.5	2,712		0.0000	1.0000	100.00
58.5	2,712		0.0000	1.0000	100.00
59.5					100.00


FORTISBC, INC.
ACCOUNT 350.10 - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1940-2009 EXPERIENCE:
1940-2009 PLACEMENT
IOWA 75-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
20
40
60
80
100
120
140

FORTISBC, INC.

ACCOUNT 350.10 - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2009 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,026,388	102,681	0.0170	0.9830	100.00
0.5	5,822,654	53	0.0000	1.0000	98.30
1.5	5,023,648	170	0.0000	1.0000	98.30
2.5	5,023,478	2,332	0.0005	0.9995	98.29
3.5	5,021,147	28,385	0.0057	0.9943	98.25
4.5	4,992,762	26,836	0.0054	0.9946	97.69
5.5	3,610,809	5,134	0.0014	0.9986	97.17
6.5	2,875,754	83	0.0000	1.0000	97.03
7.5	2,827,403	3,371	0.0012	0.9988	97.02
8.5	2,800,366	10,221	0.0037	0.9963	96.91
9.5	2,398,546	5,319	0.0022	0.9978	96.56
10.5	2,393,228	3,830	0.0016	0.9984	96.34
11.5	2,115,701	1,038	0.0005	0.9995	96.19
12.5	2,056,909	253	0.0001	0.9999	96.14
13.5	2,037,103	8,272	0.0041	0.9959	96.13
14.5	2,028,831	8,187	0.0040	0.9960	95.74
15.5	2,020,644	3,370	0.0017	0.9983	95.35
16.5	2,017,274	1,283	0.0006	0.9994	95.19
17.5	1,503,424	1,891	0.0013	0.9987	95.13
18.5	1,499,522	1,156	0.0008	0.9992	95.01
19.5	1,482,339	261	0.0002	0.9998	94.94
20.5	1,464,624	13,171	0.0090	0.9910	94.92
21.5	1,451,278	573	0.0004	0.9996	94.07
22.5	1,445,176		0.0000	1.0000	94.03
23.5	1,239,666		0.0000	1.0000	94.03
24.5	1,198,342		0.0000	1.0000	94.03
25.5	1,115,038		0.0000	1.0000	94.03
26.5	1,114,597		0.0000	1.0000	94.03
27.5	1,108,002		0.0000	1.0000	94.03
28.5	1,059,485		0.0000	1.0000	94.03
29.5	1,053,016		0.0000	1.0000	94.03
30.5	1,049,480		0.0000	1.0000	94.03
31.5	1,042,958		0.0000	1.0000	94.03
32.5	1,035,122		0.0000	1.0000	94.03
33.5	1,028,385		0.0000	1.0000	94.03
34.5	1,028,385		0.0000	1.0000	94.03
35.5	1,028,385		0.0000	1.0000	94.03
36.5	1,028,385	0	0.0000	1.0000	94.03
37.5	1,028,385		0.0000	1.0000	94.03
38.5	1,028,385		0.0000	1.0000	94.03

FORTISBC, INC.

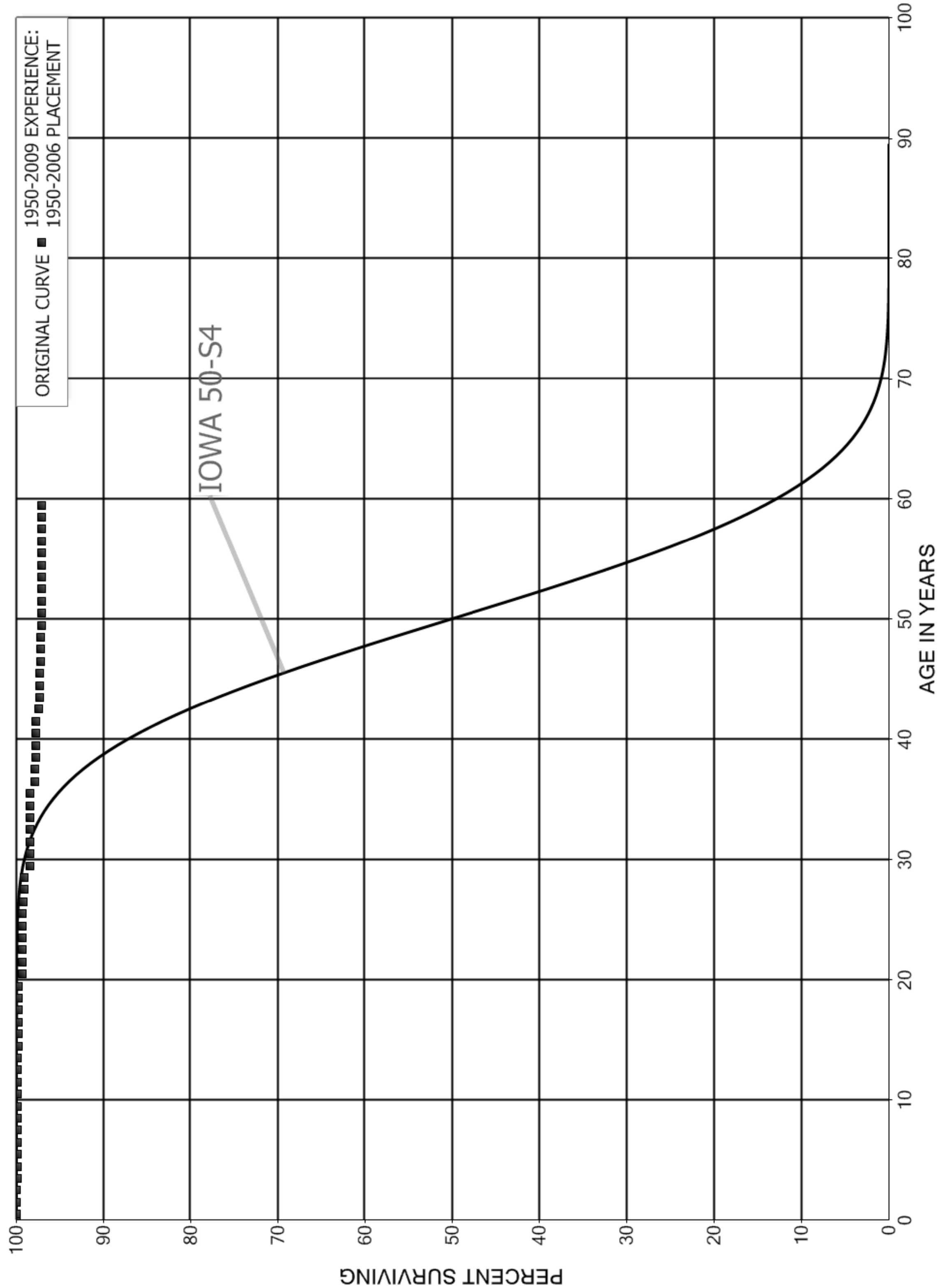
ACCOUNT 350.10 - LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2009 EXPERIENCE BAND 1940-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,028,385		0.0000	1.0000	94.03
40.5	1,028,385		0.0000	1.0000	94.03
41.5	1,028,385	0	0.0000	1.0000	94.03
42.5	1,028,385		0.0000	1.0000	94.03
43.5	1,028,385	0	0.0000	1.0000	94.03
44.5	1,028,385		0.0000	1.0000	94.03
45.5	1,028,385		0.0000	1.0000	94.03
46.5	1,013,338		0.0000	1.0000	94.03
47.5	1,000,449		0.0000	1.0000	94.03
48.5	991,221		0.0000	1.0000	94.03
49.5	991,221		0.0000	1.0000	94.03
50.5	991,221		0.0000	1.0000	94.03
51.5	989,498	0	0.0000	1.0000	94.03
52.5	901,044		0.0000	1.0000	94.03
53.5	901,044		0.0000	1.0000	94.03
54.5	901,044		0.0000	1.0000	94.03
55.5	901,044		0.0000	1.0000	94.03
56.5	901,044		0.0000	1.0000	94.03
57.5	901,044		0.0000	1.0000	94.03
58.5	901,044		0.0000	1.0000	94.03
59.5	901,044		0.0000	1.0000	94.03
60.5	901,044		0.0000	1.0000	94.03
61.5	901,044		0.0000	1.0000	94.03
62.5	901,044		0.0000	1.0000	94.03
63.5	901,044		0.0000	1.0000	94.03
64.5	901,044		0.0000	1.0000	94.03
65.5	901,044		0.0000	1.0000	94.03
66.5	901,044		0.0000	1.0000	94.03
67.5	901,044		0.0000	1.0000	94.03
68.5	901,044		0.0000	1.0000	94.03
69.5					94.03

FORTISBC, INC.
ACCOUNT 353.00 - SUBSTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 353.00 - SUBSTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1950-2006 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	139,386,344	3,248	0.0000	1.0000	100.00
0.5	139,383,096	110,537	0.0008	0.9992	100.00
1.5	139,272,558	11,686	0.0001	0.9999	99.92
2.5	139,260,872	42,242	0.0003	0.9997	99.91
3.5	130,020,020	25,553	0.0002	0.9998	99.88
4.5	110,584,196	1,618	0.0000	1.0000	99.86
5.5	104,255,694	9,061	0.0001	0.9999	99.86
6.5	93,796,553	16,657	0.0002	0.9998	99.85
7.5	93,741,114	2,488	0.0000	1.0000	99.83
8.5	90,859,492	1,725	0.0000	1.0000	99.83
9.5	89,737,911	18,413	0.0002	0.9998	99.83
10.5	89,064,104	17,802	0.0002	0.9998	99.81
11.5	86,329,604	668	0.0000	1.0000	99.79
12.5	86,328,936	4,668	0.0001	0.9999	99.79
13.5	82,214,707	6,919	0.0001	0.9999	99.78
14.5	80,319,947	1,297	0.0000	1.0000	99.77
15.5	57,635,104	1,452	0.0000	1.0000	99.77
16.5	55,799,064	14,449	0.0003	0.9997	99.77
17.5	55,344,135		0.0000	1.0000	99.74
18.5	55,344,135		0.0000	1.0000	99.74
19.5	55,135,520	241,940	0.0044	0.9956	99.74
20.5	52,760,428	311	0.0000	1.0000	99.30
21.5	51,832,707	309	0.0000	1.0000	99.30
22.5	51,832,398	496	0.0000	1.0000	99.30
23.5	48,524,118	3,299	0.0001	0.9999	99.30
24.5	44,155,360		0.0000	1.0000	99.30
25.5	43,870,521	39,757	0.0009	0.9991	99.30
26.5	43,830,764	59,683	0.0014	0.9986	99.21
27.5	40,492,042		0.0000	1.0000	99.07
28.5	40,492,042	254,310	0.0063	0.9937	99.07
29.5	35,075,046		0.0000	1.0000	98.45
30.5	35,075,046		0.0000	1.0000	98.45
31.5	26,385,873		0.0000	1.0000	98.45
32.5	25,469,588		0.0000	1.0000	98.45
33.5	25,135,733		0.0000	1.0000	98.45
34.5	22,923,512	6,246	0.0003	0.9997	98.45
35.5	22,917,266	136,555	0.0060	0.9940	98.42
36.5	16,187,761		0.0000	1.0000	97.84
37.5	16,187,761	21,315	0.0013	0.9987	97.84
38.5	16,166,446		0.0000	1.0000	97.71

FORTISBC, INC.

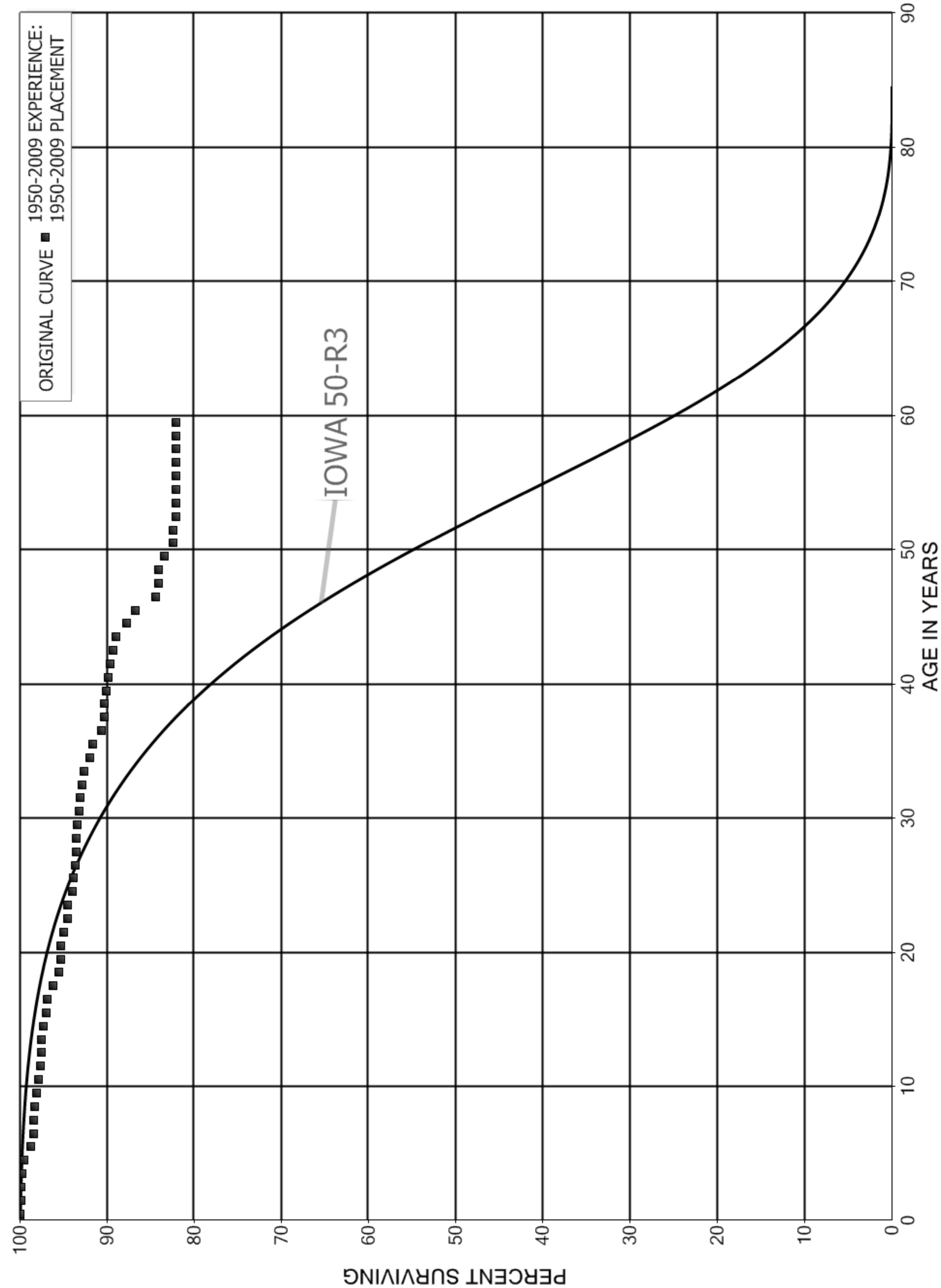
ACCOUNT 353.00 - SUBSTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1950-2006 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,166,446		0.0000	1.0000	97.71
40.5	16,166,446		0.0000	1.0000	97.71
41.5	16,166,446	57,620	0.0036	0.9964	97.71
42.5	16,108,827	15,405	0.0010	0.9990	97.36
43.5	11,774,723		0.0000	1.0000	97.27
44.5	11,774,723		0.0000	1.0000	97.27
45.5	11,774,723	7,794	0.0007	0.9993	97.27
46.5	11,766,929		0.0000	1.0000	97.20
47.5	11,766,929		0.0000	1.0000	97.20
48.5	11,766,929	14,565	0.0012	0.9988	97.20
49.5	8,203,136		0.0000	1.0000	97.08
50.5	8,203,136		0.0000	1.0000	97.08
51.5	8,203,136		0.0000	1.0000	97.08
52.5	8,203,136		0.0000	1.0000	97.08
53.5	8,203,136		0.0000	1.0000	97.08
54.5	8,203,136		0.0000	1.0000	97.08
55.5	8,203,136		0.0000	1.0000	97.08
56.5	8,203,136		0.0000	1.0000	97.08
57.5	8,203,136		0.0000	1.0000	97.08
58.5	8,203,136		0.0000	1.0000	97.08
59.5					97.08

FORTISBC, INC.
ACCOUNT 355.00 - POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 355.00 - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1950-2009 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	76,558,352	51,071	0.0007	0.9993	100.00
0.5	75,637,606	60,862	0.0008	0.9992	99.93
1.5	75,576,745	47,178	0.0006	0.9994	99.85
2.5	67,194,156	25,216	0.0004	0.9996	99.79
3.5	67,168,940	180,666	0.0027	0.9973	99.75
4.5	65,009,915	479,288	0.0074	0.9926	99.48
5.5	57,183,152	177,826	0.0031	0.9969	98.75
6.5	48,272,028	47,597	0.0010	0.9990	98.44
7.5	47,303,184	32,455	0.0007	0.9993	98.35
8.5	46,063,520	95,768	0.0021	0.9979	98.28
9.5	43,315,999	108,718	0.0025	0.9975	98.08
10.5	42,390,562	105,198	0.0025	0.9975	97.83
11.5	39,165,461	41,365	0.0011	0.9989	97.59
12.5	37,533,638	11,305	0.0003	0.9997	97.48
13.5	33,109,847	67,102	0.0020	0.9980	97.45
14.5	32,554,747	118,492	0.0036	0.9964	97.26
15.5	28,539,483	26,247	0.0009	0.9991	96.90
16.5	27,646,791	194,261	0.0070	0.9930	96.81
17.5	26,855,069	169,683	0.0063	0.9937	96.13
18.5	25,799,697	56,567	0.0022	0.9978	95.53
19.5	24,990,548	19,008	0.0008	0.9992	95.32
20.5	24,335,469	78,238	0.0032	0.9968	95.24
21.5	24,004,329	105,466	0.0044	0.9956	94.94
22.5	22,434,116	1,013	0.0000	1.0000	94.52
23.5	21,719,304	142,414	0.0066	0.9934	94.52
24.5	19,014,000	3,194	0.0002	0.9998	93.90
25.5	17,385,191	51,721	0.0030	0.9970	93.88
26.5	16,509,262	11,031	0.0007	0.9993	93.60
27.5	15,879,442	5,816	0.0004	0.9996	93.54
28.5	15,557,683	15,561	0.0010	0.9990	93.50
29.5	14,789,859	41,806	0.0028	0.9972	93.41
30.5	14,532,366	16,191	0.0011	0.9989	93.15
31.5	14,455,867	36,920	0.0026	0.9974	93.04
32.5	13,867,033	20,858	0.0015	0.9985	92.81
33.5	12,720,005	97,354	0.0077	0.9923	92.67
34.5	12,446,202	45,679	0.0037	0.9963	91.96
35.5	12,400,523	142,308	0.0115	0.9885	91.62
36.5	12,258,214	31,234	0.0025	0.9975	90.57
37.5	12,226,980	521	0.0000	1.0000	90.34
38.5	12,226,459	34,086	0.0028	0.9972	90.33

FORTISBC, INC.

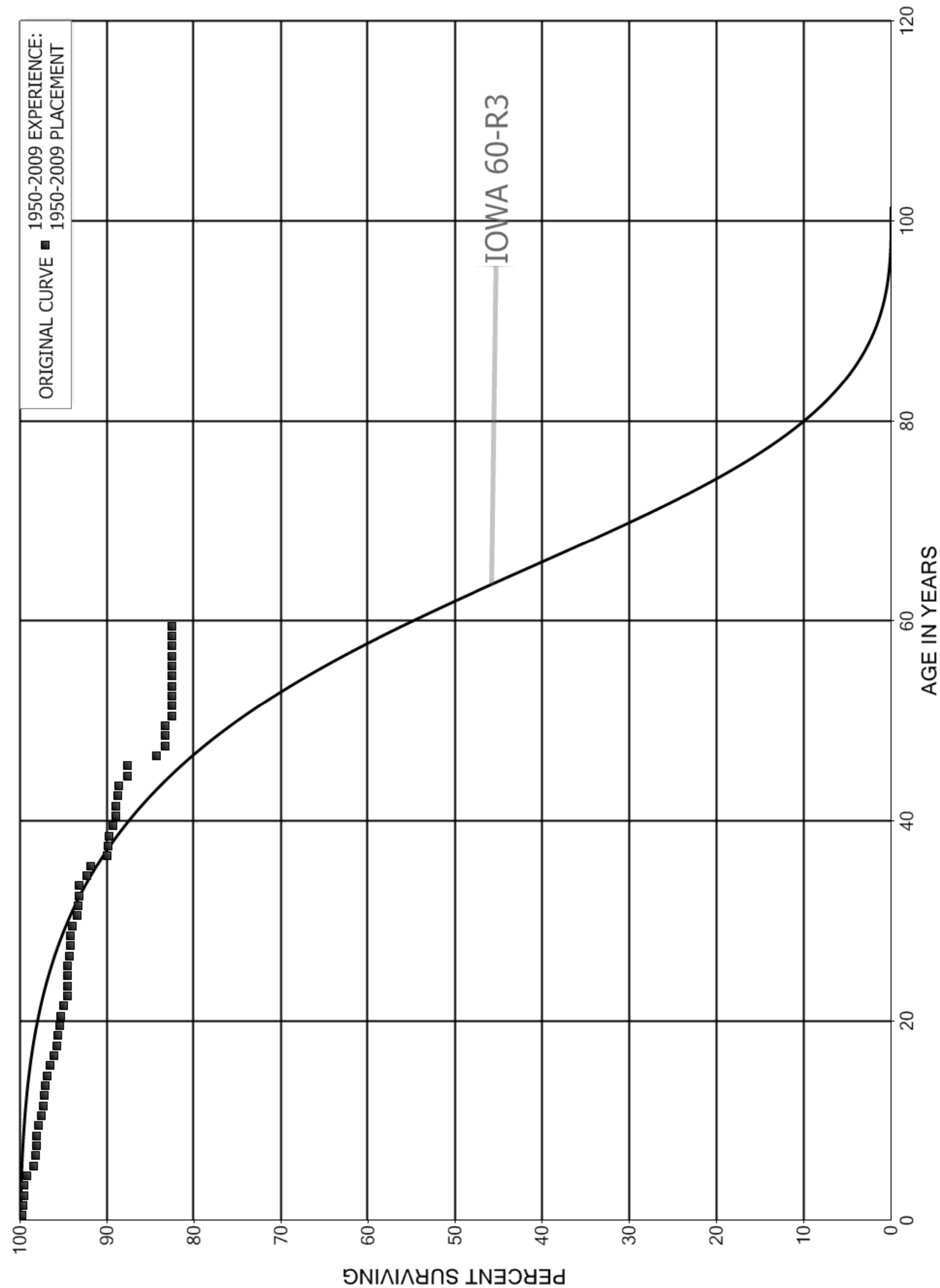
ACCOUNT 355.00 - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1950-2009 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,192,373	29,437	0.0024	0.9976	90.08
40.5	12,162,936	27,146	0.0022	0.9978	89.86
41.5	12,135,790	44,216	0.0036	0.9964	89.66
42.5	12,091,574	57,923	0.0048	0.9952	89.34
43.5	12,033,651	165,812	0.0138	0.9862	88.91
44.5	8,768,577	95,096	0.0108	0.9892	87.68
45.5	8,315,508	228,877	0.0275	0.9725	86.73
46.5	8,024,906	23,694	0.0030	0.9970	84.35
47.5	7,558,160	4,490	0.0006	0.9994	84.10
48.5	7,302,738	54,821	0.0075	0.9925	84.05
49.5	7,247,917	89,942	0.0124	0.9876	83.42
50.5	7,152,005	2,512	0.0004	0.9996	82.38
51.5	7,002,902	24,891	0.0036	0.9964	82.35
52.5	632,199		0.0000	1.0000	82.06
53.5	632,199		0.0000	1.0000	82.06
54.5	632,199		0.0000	1.0000	82.06
55.5	632,199		0.0000	1.0000	82.06
56.5	632,199		0.0000	1.0000	82.06
57.5	632,199		0.0000	1.0000	82.06
58.5	632,199		0.0000	1.0000	82.06
59.5					82.06

FORTISBC, INC.
ACCOUNT 356.00 - CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 356.00 - CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1950-2009 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	74,382,693	192,002	0.0026	0.9974	100.00
0.5	73,284,855	82,388	0.0011	0.9989	99.74
1.5	73,202,467	55,017	0.0008	0.9992	99.63
2.5	64,811,729	33,102	0.0005	0.9995	99.55
3.5	64,778,627	193,903	0.0030	0.9970	99.50
4.5	64,040,872	490,980	0.0077	0.9923	99.21
5.5	56,889,230	187,446	0.0033	0.9967	98.45
6.5	49,012,825	12,183	0.0002	0.9998	98.12
7.5	48,090,867	30,494	0.0006	0.9994	98.10
8.5	45,681,494	106,526	0.0023	0.9977	98.03
9.5	42,845,483	119,036	0.0028	0.9972	97.81
10.5	42,726,447	112,540	0.0026	0.9974	97.53
11.5	39,283,146	52,852	0.0013	0.9987	97.28
12.5	37,611,371	19,196	0.0005	0.9995	97.15
13.5	32,922,852	74,645	0.0023	0.9977	97.10
14.5	32,511,741	124,624	0.0038	0.9962	96.88
15.5	28,177,687	141,085	0.0050	0.9950	96.51
16.5	27,214,244	88,306	0.0032	0.9968	96.02
17.5	26,425,603	28,209	0.0011	0.9989	95.71
18.5	25,560,918	58,848	0.0023	0.9977	95.61
19.5	24,620,068	26,066	0.0011	0.9989	95.39
20.5	23,892,235	86,444	0.0036	0.9964	95.29
21.5	22,338,985	106,461	0.0048	0.9952	94.94
22.5	21,469,224	1,463	0.0001	0.9999	94.49
23.5	20,792,814	3,890	0.0002	0.9998	94.48
24.5	18,781,765	2,421	0.0001	0.9999	94.47
25.5	17,130,033	30,163	0.0018	0.9982	94.45
26.5	16,648,335	11,838	0.0007	0.9993	94.29
27.5	15,985,263	5,668	0.0004	0.9996	94.22
28.5	15,752,575	47,347	0.0030	0.9970	94.19
29.5	15,163,966	79,874	0.0053	0.9947	93.90
30.5	14,740,811	22,505	0.0015	0.9985	93.41
31.5	14,640,555	15,643	0.0011	0.9989	93.27
32.5	14,054,057	3,672	0.0003	0.9997	93.17
33.5	13,153,047	126,187	0.0096	0.9904	93.14
34.5	12,831,416	59,515	0.0046	0.9954	92.25
35.5	12,771,901	255,213	0.0200	0.9800	91.82
36.5	12,516,688	14,928	0.0012	0.9988	89.99
37.5	12,501,760	19,078	0.0015	0.9985	89.88
38.5	12,482,682	66,662	0.0053	0.9947	89.74

FORTISBC, INC.

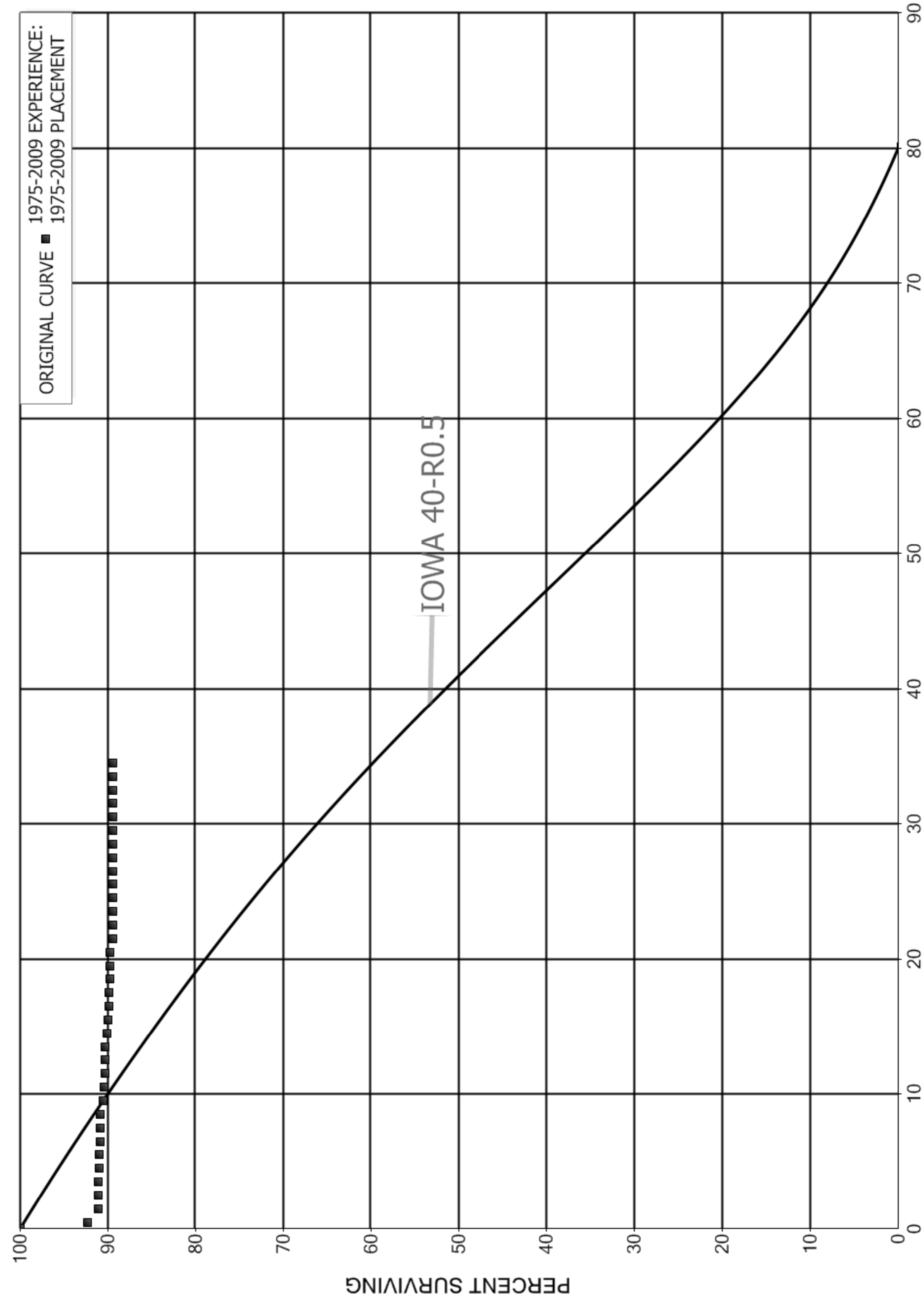
ACCOUNT 356.00 - CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1950-2009 EXPERIENCE BAND 1950-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,416,020	47,767	0.0038	0.9962	89.26
40.5	12,368,253		0.0000	1.0000	88.92
41.5	12,368,253	27,135	0.0022	0.9978	88.92
42.5	12,341,118	17,126	0.0014	0.9986	88.72
43.5	12,323,992	130,039	0.0106	0.9894	88.60
44.5	9,099,316	7,673	0.0008	0.9992	87.67
45.5	9,091,643	347,847	0.0383	0.9617	87.59
46.5	8,682,070	96,267	0.0111	0.9889	84.24
47.5	8,144,049	0	0.0000	1.0000	83.31
48.5	7,481,782		0.0000	1.0000	83.31
49.5	7,481,782	70,991	0.0095	0.9905	83.31
50.5	7,388,823	1,972	0.0003	0.9997	82.52
51.5	7,270,795		0.0000	1.0000	82.49
52.5	1,447,409		0.0000	1.0000	82.49
53.5	1,447,409		0.0000	1.0000	82.49
54.5	1,447,409		0.0000	1.0000	82.49
55.5	1,447,409		0.0000	1.0000	82.49
56.5	1,447,409		0.0000	1.0000	82.49
57.5	1,447,409		0.0000	1.0000	82.49
58.5	1,447,409		0.0000	1.0000	82.49
59.5					82.49

FORTISBC, INC.
ACCOUNT 359.00 - ROADS AND TRAILS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

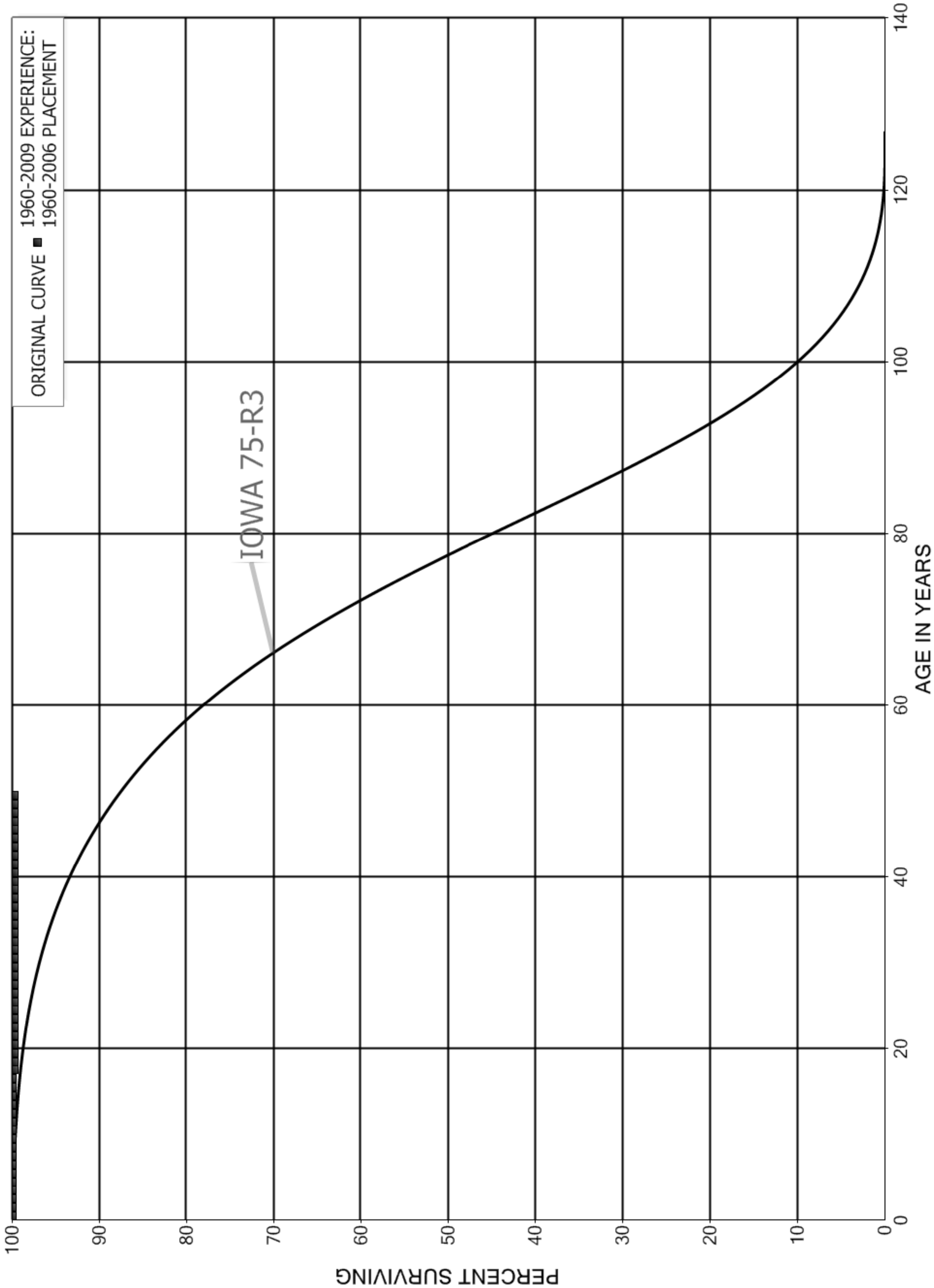
ACCOUNT 359.00 - ROADS AND TRAILS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2009 EXPERIENCE BAND 1975-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,231,354	95,119	0.0772	0.9228	100.00
0.5	831,986	10,735	0.0129	0.9871	92.28
1.5	821,250	5	0.0000	1.0000	91.08
2.5	821,245	67	0.0001	0.9999	91.08
3.5	821,179	810	0.0010	0.9990	91.08
4.5	820,369	766	0.0009	0.9991	90.99
5.5	418,826	146	0.0003	0.9997	90.90
6.5	109,056	2	0.0000	1.0000	90.87
7.5	109,054	96	0.0009	0.9991	90.87
8.5	108,957	292	0.0027	0.9973	90.79
9.5	108,666	152	0.0014	0.9986	90.55
10.5	108,514	109	0.0010	0.9990	90.42
11.5	108,405	30	0.0003	0.9997	90.33
12.5	108,375	7	0.0001	0.9999	90.30
13.5	108,368	236	0.0022	0.9978	90.30
14.5	108,132	234	0.0022	0.9978	90.10
15.5	107,898	96	0.0009	0.9991	89.91
16.5	107,802	37	0.0003	0.9997	89.83
17.5	107,765	54	0.0005	0.9995	89.79
18.5	107,711	33	0.0003	0.9997	89.75
19.5	107,679	7	0.0001	0.9999	89.72
20.5	107,671	376	0.0035	0.9965	89.72
21.5	107,295	16	0.0002	0.9998	89.40
22.5	107,279		0.0000	1.0000	89.39
23.5	107,279		0.0000	1.0000	89.39
24.5	107,279		0.0000	1.0000	89.39
25.5	107,279		0.0000	1.0000	89.39
26.5	107,279		0.0000	1.0000	89.39
27.5	49,792		0.0000	1.0000	89.39
28.5	49,792		0.0000	1.0000	89.39
29.5	23,498		0.0000	1.0000	89.39
30.5	21,121		0.0000	1.0000	89.39
31.5	20,481		0.0000	1.0000	89.39
32.5	17,902		0.0000	1.0000	89.39
33.5	4,416		0.0000	1.0000	89.39
34.5					89.39

FORTISBC, INC.
ACCOUNT 360.10 - LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 360.10 - LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,495,621	0	0.0000	1.0000	100.00
0.5	8,495,620	6	0.0000	1.0000	100.00
1.5	8,495,615	3	0.0000	1.0000	100.00
2.5	8,495,612		0.0000	1.0000	100.00
3.5	7,842,657		0.0000	1.0000	100.00
4.5	7,842,657		0.0000	1.0000	100.00
5.5	7,842,655		0.0000	1.0000	100.00
6.5	7,842,655		0.0000	1.0000	100.00
7.5	7,842,655		0.0000	1.0000	100.00
8.5	7,824,523		0.0000	1.0000	100.00
9.5	7,743,417		0.0000	1.0000	100.00
10.5	7,555,541		0.0000	1.0000	100.00
11.5	7,425,549		0.0000	1.0000	100.00
12.5	7,425,549		0.0000	1.0000	100.00
13.5	7,425,549		0.0000	1.0000	100.00
14.5	7,425,549		0.0000	1.0000	100.00
15.5	7,425,549		0.0000	1.0000	100.00
16.5	7,425,549	18,511	0.0025	0.9975	100.00
17.5	7,407,038		0.0000	1.0000	99.75
18.5	7,307,557		0.0000	1.0000	99.75
19.5	7,270,691		0.0000	1.0000	99.75
20.5	7,270,428		0.0000	1.0000	99.75
21.5	7,246,515		0.0000	1.0000	99.75
22.5	7,197,987		0.0000	1.0000	99.75
23.5	7,089,257		0.0000	1.0000	99.75
24.5	6,959,628		0.0000	1.0000	99.75
25.5	6,933,806		0.0000	1.0000	99.75
26.5	6,762,251		0.0000	1.0000	99.75
27.5	6,675,070		0.0000	1.0000	99.75
28.5	6,605,547		0.0000	1.0000	99.75
29.5	6,484,551		0.0000	1.0000	99.75
30.5	6,390,265		0.0000	1.0000	99.75
31.5	6,312,448		0.0000	1.0000	99.75
32.5	6,283,515		0.0000	1.0000	99.75
33.5	6,171,836		0.0000	1.0000	99.75
34.5	6,137,907		0.0000	1.0000	99.75
35.5	6,137,907		0.0000	1.0000	99.75
36.5	6,137,907		0.0000	1.0000	99.75
37.5	6,137,907		0.0000	1.0000	99.75
38.5	6,137,907		0.0000	1.0000	99.75

FORTISBC, INC.

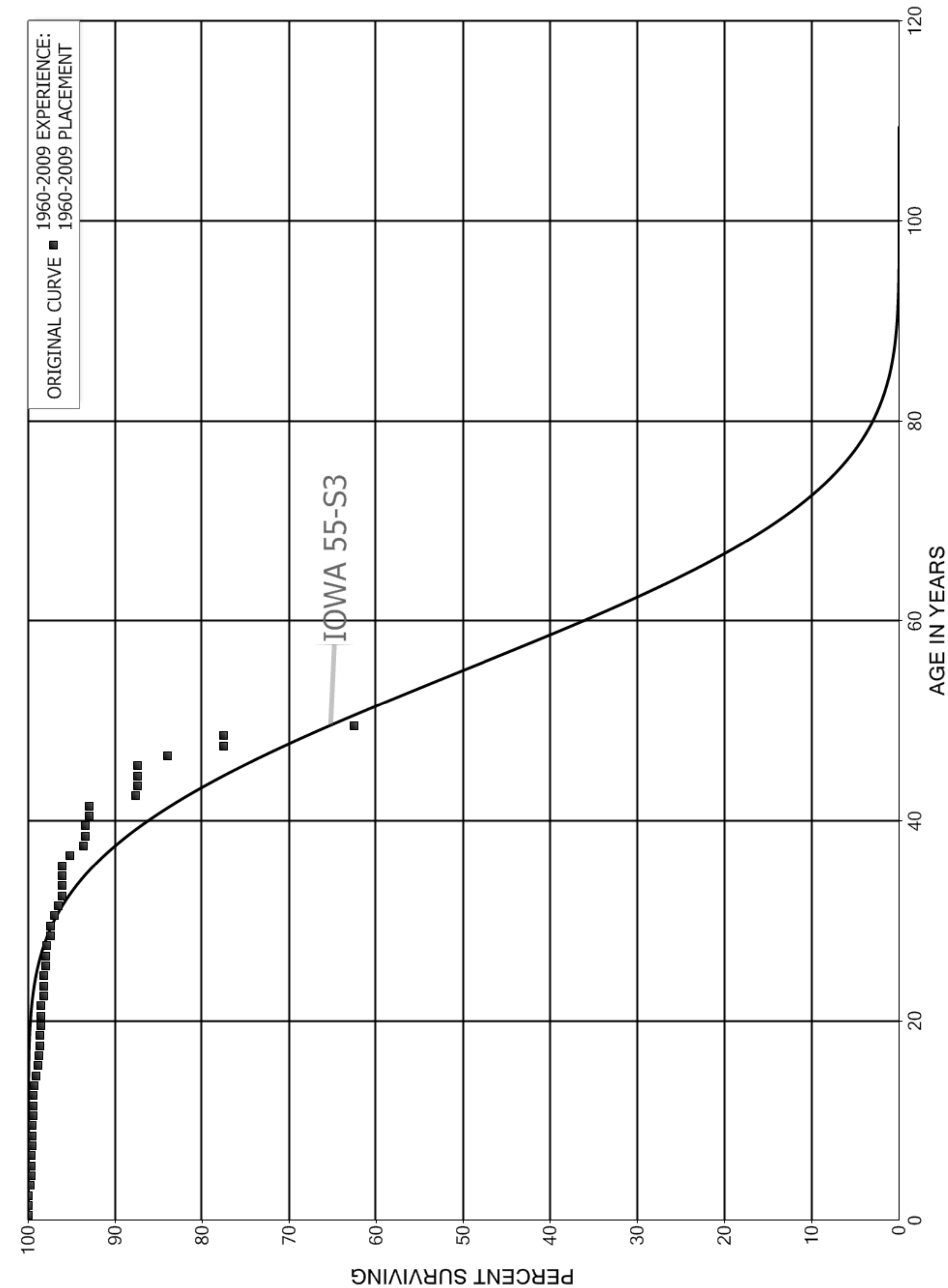
ACCOUNT 360.10 - LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,137,907		0.0000	1.0000	99.75
40.5	6,137,907		0.0000	1.0000	99.75
41.5	6,137,907		0.0000	1.0000	99.75
42.5	6,137,907		0.0000	1.0000	99.75
43.5	6,137,907		0.0000	1.0000	99.75
44.5	6,137,907		0.0000	1.0000	99.75
45.5	6,137,907		0.0000	1.0000	99.75
46.5	6,137,907		0.0000	1.0000	99.75
47.5	6,137,907		0.0000	1.0000	99.75
48.5	6,137,907		0.0000	1.0000	99.75
49.5					99.75

FORTISBC, INC.
ACCOUNT 362.00 - SUBSTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



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FORTISBC, INC.

ACCOUNT 362.00 - SUBSTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2009 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	185,888,879	25,565	0.0001	0.9999	100.00
0.5	168,188,500	36,039	0.0002	0.9998	99.99
1.5	138,990,044	46,718	0.0003	0.9997	99.96
2.5	128,394,037	319,592	0.0025	0.9975	99.93
3.5	127,778,237	44,615	0.0003	0.9997	99.68
4.5	127,733,623	39,838	0.0003	0.9997	99.65
5.5	126,120,669	30,700	0.0002	0.9998	99.62
6.5	98,037,950	41,318	0.0004	0.9996	99.59
7.5	97,161,167	33,161	0.0003	0.9997	99.55
8.5	95,464,846	39,967	0.0004	0.9996	99.52
9.5	92,216,863	34,528	0.0004	0.9996	99.47
10.5	89,134,698	25,855	0.0003	0.9997	99.44
11.5	88,766,208	40,591	0.0005	0.9995	99.41
12.5	86,294,150	36,562	0.0004	0.9996	99.36
13.5	83,164,063	213,998	0.0026	0.9974	99.32
14.5	79,056,144	154,813	0.0020	0.9980	99.07
15.5	75,634,837	129,891	0.0017	0.9983	98.87
16.5	73,937,353	61,220	0.0008	0.9992	98.70
17.5	73,031,911	16,124	0.0002	0.9998	98.62
18.5	65,923,902	42,746	0.0006	0.9994	98.60
19.5	63,302,279	8,860	0.0001	0.9999	98.53
20.5	62,733,443	37,013	0.0006	0.9994	98.52
21.5	61,466,369	154,059	0.0025	0.9975	98.46
22.5	55,928,038	11,021	0.0002	0.9998	98.22
23.5	55,358,156	20,787	0.0004	0.9996	98.20
24.5	55,026,689	84,535	0.0015	0.9985	98.16
25.5	50,674,608	116	0.0000	1.0000	98.01
26.5	47,089,854	107,027	0.0023	0.9977	98.01
27.5	45,183,111	168,895	0.0037	0.9963	97.79
28.5	43,762,137	1,184	0.0000	1.0000	97.42
29.5	39,381,283	177,189	0.0045	0.9955	97.42
30.5	38,036,209	168,473	0.0044	0.9956	96.98
31.5	29,122,723	131,156	0.0045	0.9955	96.55
32.5	26,487,098	930	0.0000	1.0000	96.11
33.5	25,223,682		0.0000	1.0000	96.11
34.5	23,202,899		0.0000	1.0000	96.11
35.5	22,912,748	231,421	0.0101	0.9899	96.11
36.5	22,217,902	344,643	0.0155	0.9845	95.14
37.5	20,977,092	56,159	0.0027	0.9973	93.66
38.5	20,711,174		0.0000	1.0000	93.41

FORTISBC, INC.

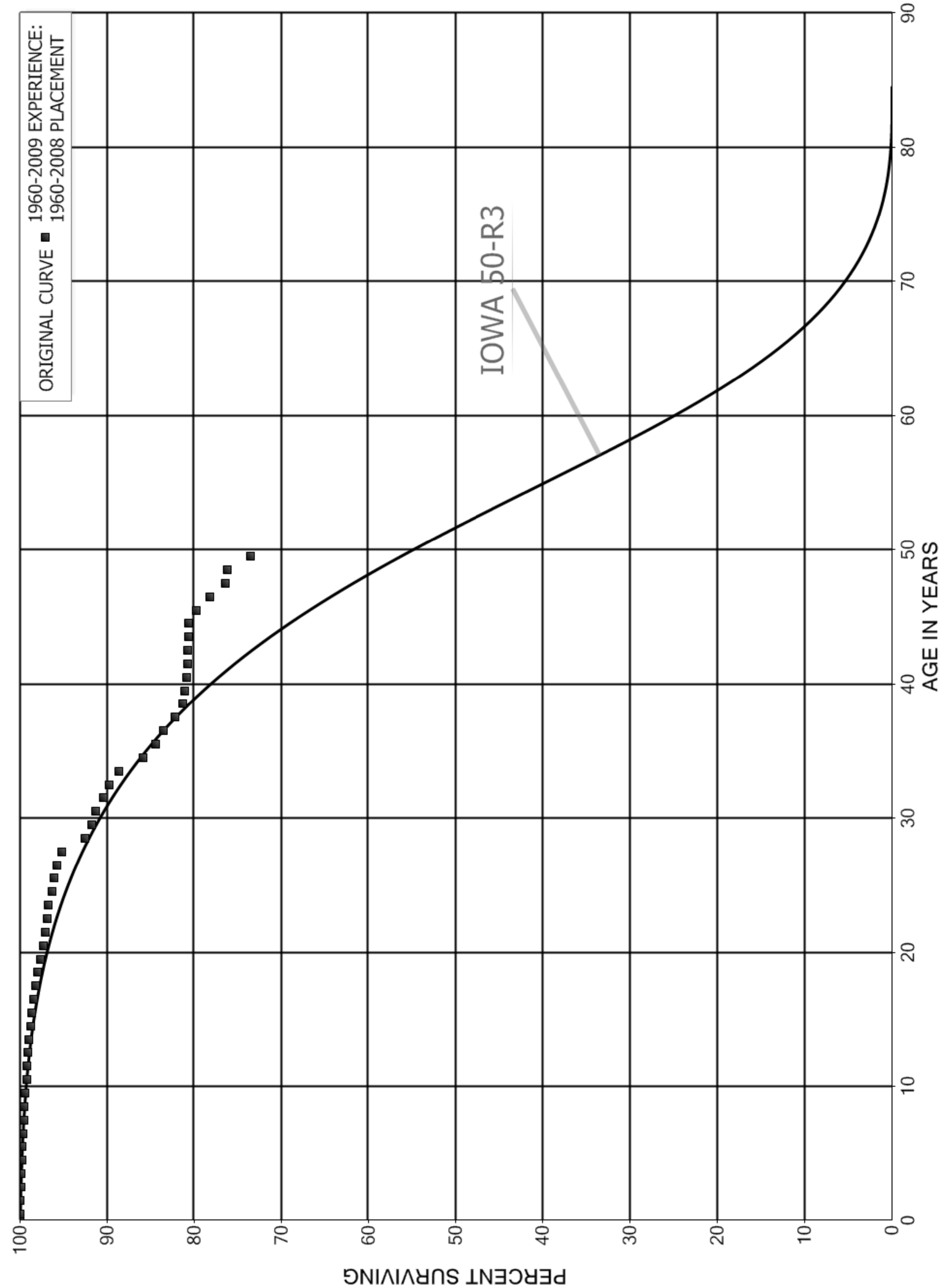
ACCOUNT 362.00 - SUBSTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2009 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	19,754,539	89,743	0.0045	0.9955	93.41
40.5	12,484,087	1,459	0.0001	0.9999	92.99
41.5	9,245,594	532,227	0.0576	0.9424	92.98
42.5	8,713,367	28,362	0.0033	0.9967	87.63
43.5	3,575,635		0.0000	1.0000	87.34
44.5	3,575,635		0.0000	1.0000	87.34
45.5	3,575,635	138,565	0.0388	0.9612	87.34
46.5	3,437,070	266,032	0.0774	0.9226	83.96
47.5	3,070,277		0.0000	1.0000	77.46
48.5	2,505,610	484,519	0.1934	0.8066	77.46
49.5					62.48

FORTISBC, INC.
ACCOUNT 364.00 - POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 364.00 - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	133,055,033	35,031	0.0003	0.9997	100.00
0.5	133,020,002	53,737	0.0004	0.9996	99.97
1.5	121,185,595	63,068	0.0005	0.9995	99.93
2.5	111,619,702	80,906	0.0007	0.9993	99.88
3.5	95,915,567	53,877	0.0006	0.9994	99.81
4.5	88,171,066	63,098	0.0007	0.9993	99.75
5.5	82,701,945	74,570	0.0009	0.9991	99.68
6.5	82,627,375	57,085	0.0007	0.9993	99.59
7.5	82,570,290	59,802	0.0007	0.9993	99.52
8.5	77,894,308	84,083	0.0011	0.9989	99.45
9.5	73,861,849	93,669	0.0013	0.9987	99.34
10.5	69,910,992	62,341	0.0009	0.9991	99.22
11.5	66,132,678	74,537	0.0011	0.9989	99.13
12.5	61,916,470	79,268	0.0013	0.9987	99.02
13.5	58,556,647	83,223	0.0014	0.9986	98.89
14.5	53,517,045	93,613	0.0017	0.9983	98.75
15.5	49,095,515	103,042	0.0021	0.9979	98.58
16.5	46,230,799	90,245	0.0020	0.9980	98.37
17.5	36,362,505	82,435	0.0023	0.9977	98.18
18.5	34,746,350	116,226	0.0033	0.9967	97.96
19.5	33,407,582	99,150	0.0030	0.9970	97.63
20.5	31,881,130	76,745	0.0024	0.9976	97.34
21.5	30,510,949	79,568	0.0026	0.9974	97.10
22.5	29,701,308	50,381	0.0017	0.9983	96.85
23.5	28,275,024	111,418	0.0039	0.9961	96.69
24.5	26,855,443	55,186	0.0021	0.9979	96.31
25.5	25,865,896	107,634	0.0042	0.9958	96.11
26.5	24,755,386	144,916	0.0059	0.9941	95.71
27.5	23,672,170	666,337	0.0281	0.9719	95.15
28.5	21,031,339	177,076	0.0084	0.9916	92.47
29.5	19,449,029	95,817	0.0049	0.9951	91.69
30.5	18,169,004	174,039	0.0096	0.9904	91.24
31.5	16,935,989	117,284	0.0069	0.9931	90.36
32.5	15,800,215	199,960	0.0127	0.9873	89.74
33.5	14,710,097	454,270	0.0309	0.9691	88.60
34.5	13,608,839	235,410	0.0173	0.9827	85.87
35.5	13,373,429	143,697	0.0107	0.9893	84.38
36.5	13,229,733	209,959	0.0159	0.9841	83.48
37.5	13,019,773	134,251	0.0103	0.9897	82.15
38.5	12,885,522	40,232	0.0031	0.9969	81.30

FORTISBC, INC.

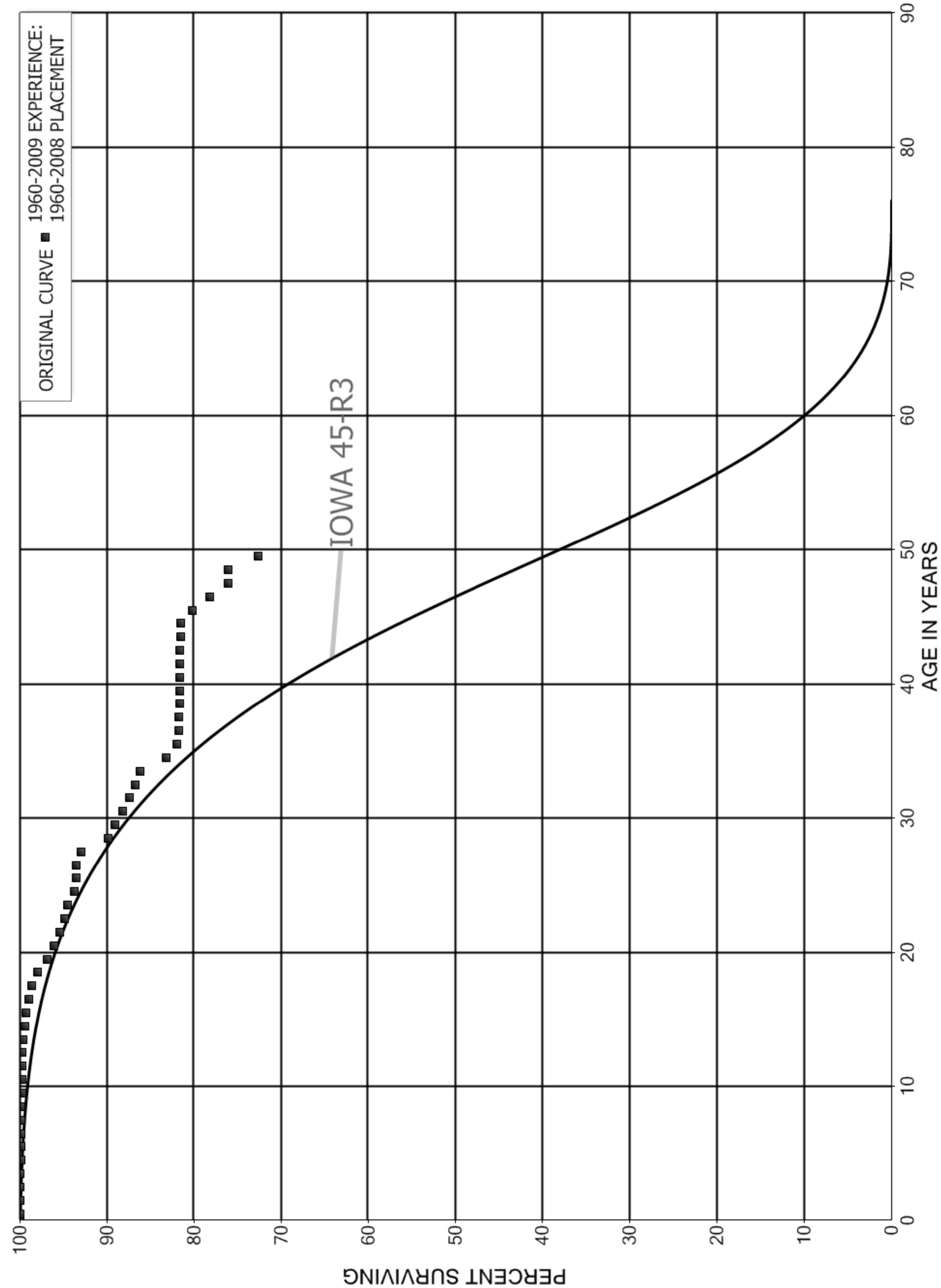
ACCOUNT 364.00 - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,845,290	33,943	0.0026	0.9974	81.05
40.5	12,811,348	23,489	0.0018	0.9982	80.84
41.5	12,787,859	2,570	0.0002	0.9998	80.69
42.5	12,785,289	10,634	0.0008	0.9992	80.67
43.5	12,774,656	6,018	0.0005	0.9995	80.60
44.5	12,768,637	130,474	0.0102	0.9898	80.57
45.5	12,638,163	250,732	0.0198	0.9802	79.74
46.5	12,387,431	288,090	0.0233	0.9767	78.16
47.5	12,099,341	19,628	0.0016	0.9984	76.34
48.5	12,079,714	433,826	0.0359	0.9641	76.22
49.5					73.48

FORTISBC, INC.
ACCOUNT 365.00 - CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 365.00 - CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	217,822,975	34,575	0.0002	0.9998	100.00
0.5	217,788,400	37,436	0.0002	0.9998	99.98
1.5	199,731,622	45,312	0.0002	0.9998	99.97
2.5	183,151,610	40,825	0.0002	0.9998	99.94
3.5	161,526,747	99,486	0.0006	0.9994	99.92
4.5	150,337,962	11,293	0.0001	0.9999	99.86
5.5	142,358,079	42,664	0.0003	0.9997	99.85
6.5	133,246,625	5,718	0.0000	1.0000	99.82
7.5	128,318,161	18,541	0.0001	0.9999	99.82
8.5	120,744,780	49,446	0.0004	0.9996	99.80
9.5	115,447,684	63,297	0.0005	0.9995	99.76
10.5	110,400,123	6,378	0.0001	0.9999	99.71
11.5	105,147,653	19,086	0.0002	0.9998	99.70
12.5	95,652,229	48,767	0.0005	0.9995	99.68
13.5	90,158,924	188,621	0.0021	0.9979	99.63
14.5	84,856,657	134,128	0.0016	0.9984	99.43
15.5	75,955,435	238,275	0.0031	0.9969	99.27
16.5	69,458,261	277,433	0.0040	0.9960	98.96
17.5	59,262,960	333,685	0.0056	0.9944	98.56
18.5	54,513,858	645,375	0.0118	0.9882	98.01
19.5	49,292,649	418,079	0.0085	0.9915	96.85
20.5	46,274,006	321,745	0.0070	0.9930	96.03
21.5	43,754,839	222,133	0.0051	0.9949	95.36
22.5	41,501,832	184,575	0.0044	0.9956	94.87
23.5	38,989,295	277,278	0.0071	0.9929	94.45
24.5	36,731,221	106,387	0.0029	0.9971	93.78
25.5	34,633,375	10,351	0.0003	0.9997	93.51
26.5	33,024,233	193,734	0.0059	0.9941	93.48
27.5	30,053,941	1,005,374	0.0335	0.9665	92.93
28.5	26,257,937	221,898	0.0085	0.9915	89.82
29.5	23,775,973	223,086	0.0094	0.9906	89.06
30.5	21,799,425	203,575	0.0093	0.9907	88.23
31.5	20,435,926	169,027	0.0083	0.9917	87.40
32.5	19,242,921	111,137	0.0058	0.9942	86.68
33.5	18,381,469	639,368	0.0348	0.9652	86.18
34.5	17,174,179	262,315	0.0153	0.9847	83.18
35.5	16,911,864	28,682	0.0017	0.9983	81.91
36.5	16,883,182	19,695	0.0012	0.9988	81.77
37.5	16,863,487	10,175	0.0006	0.9994	81.68
38.5	16,853,311	3,419	0.0002	0.9998	81.63

FORTISBC, INC.

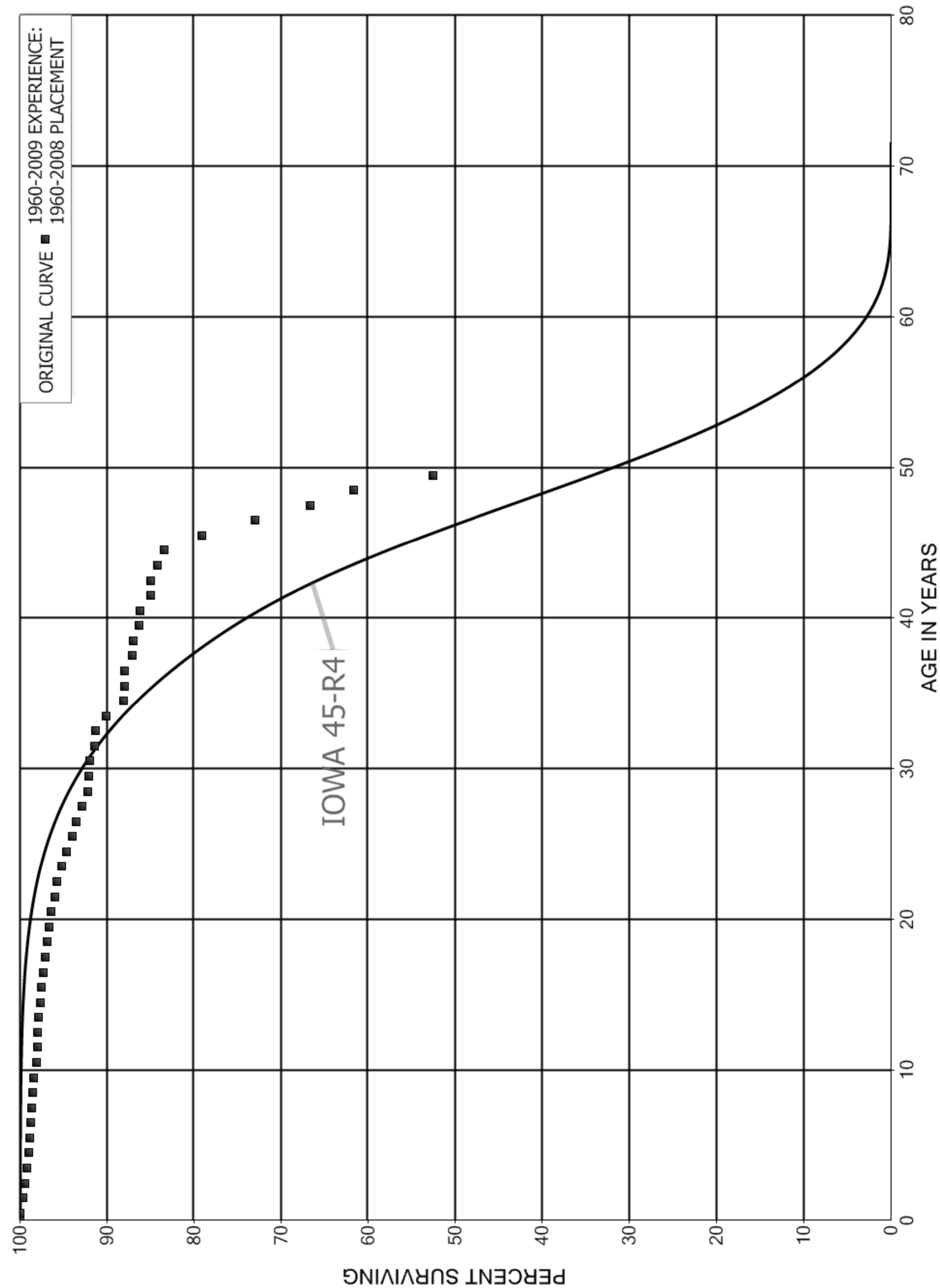
ACCOUNT 365.00 - CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,849,892	3,402	0.0002	0.9998	81.61
40.5	16,846,491	1,554	0.0001	0.9999	81.60
41.5	16,844,936	1,265	0.0001	0.9999	81.59
42.5	16,843,671	9,713	0.0006	0.9994	81.58
43.5	16,833,959	3,170	0.0002	0.9998	81.54
44.5	16,830,789	276,717	0.0164	0.9836	81.52
45.5	16,554,072	418,402	0.0253	0.9747	80.18
46.5	16,135,669	430,270	0.0267	0.9733	78.15
47.5	15,705,399	10,615	0.0007	0.9993	76.07
48.5	15,694,785	708,815	0.0452	0.9548	76.02
49.5					72.58

FORTISBC, INC.
ACCOUNT 368.00 - LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 368.00 - LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	108,867,573	87,451	0.0008	0.9992	100.00
0.5	108,780,123	332,537	0.0031	0.9969	99.92
1.5	101,035,435	200,215	0.0020	0.9980	99.61
2.5	88,577,480	172,483	0.0019	0.9981	99.42
3.5	73,151,037	167,980	0.0023	0.9977	99.22
4.5	67,457,881	92,322	0.0014	0.9986	99.00
5.5	62,451,129	89,860	0.0014	0.9986	98.86
6.5	57,273,576	40,688	0.0007	0.9993	98.72
7.5	53,367,571	58,000	0.0011	0.9989	98.65
8.5	50,051,124	90,790	0.0018	0.9982	98.54
9.5	47,087,854	167,996	0.0036	0.9964	98.36
10.5	44,710,110	7,176	0.0002	0.9998	98.01
11.5	43,405,951	36,099	0.0008	0.9992	97.99
12.5	42,321,226	34,574	0.0008	0.9992	97.91
13.5	41,271,015	84,579	0.0020	0.9980	97.83
14.5	40,049,095	37,217	0.0009	0.9991	97.63
15.5	38,131,874	89,135	0.0023	0.9977	97.54
16.5	36,719,687	78,992	0.0022	0.9978	97.31
17.5	29,761,066	70,232	0.0024	0.9976	97.10
18.5	29,342,763	72,599	0.0025	0.9975	96.88
19.5	28,927,525	63,309	0.0022	0.9978	96.64
20.5	28,366,615	134,747	0.0048	0.9952	96.42
21.5	27,829,485	76,418	0.0027	0.9973	95.97
22.5	27,420,211	141,617	0.0052	0.9948	95.70
23.5	26,785,360	172,283	0.0064	0.9936	95.21
24.5	25,884,930	190,061	0.0073	0.9927	94.60
25.5	25,299,340	114,909	0.0045	0.9955	93.90
26.5	24,611,232	179,723	0.0073	0.9927	93.48
27.5	23,659,469	163,506	0.0069	0.9931	92.79
28.5	21,883,987	31,147	0.0014	0.9986	92.15
29.5	20,795,812	28,039	0.0013	0.9987	92.02
30.5	19,840,206	109,647	0.0055	0.9945	91.90
31.5	18,628,550	16,392	0.0009	0.9991	91.39
32.5	17,771,256	251,784	0.0142	0.9858	91.31
33.5	16,705,057	363,920	0.0218	0.9782	90.01
34.5	15,781,832	11,251	0.0007	0.9993	88.05
35.5	15,770,581	6,856	0.0004	0.9996	87.99
36.5	15,763,725	150,251	0.0095	0.9905	87.95
37.5	15,613,474	19,612	0.0013	0.9987	87.11
38.5	15,593,863	137,997	0.0088	0.9912	87.00

FORTISBC, INC.

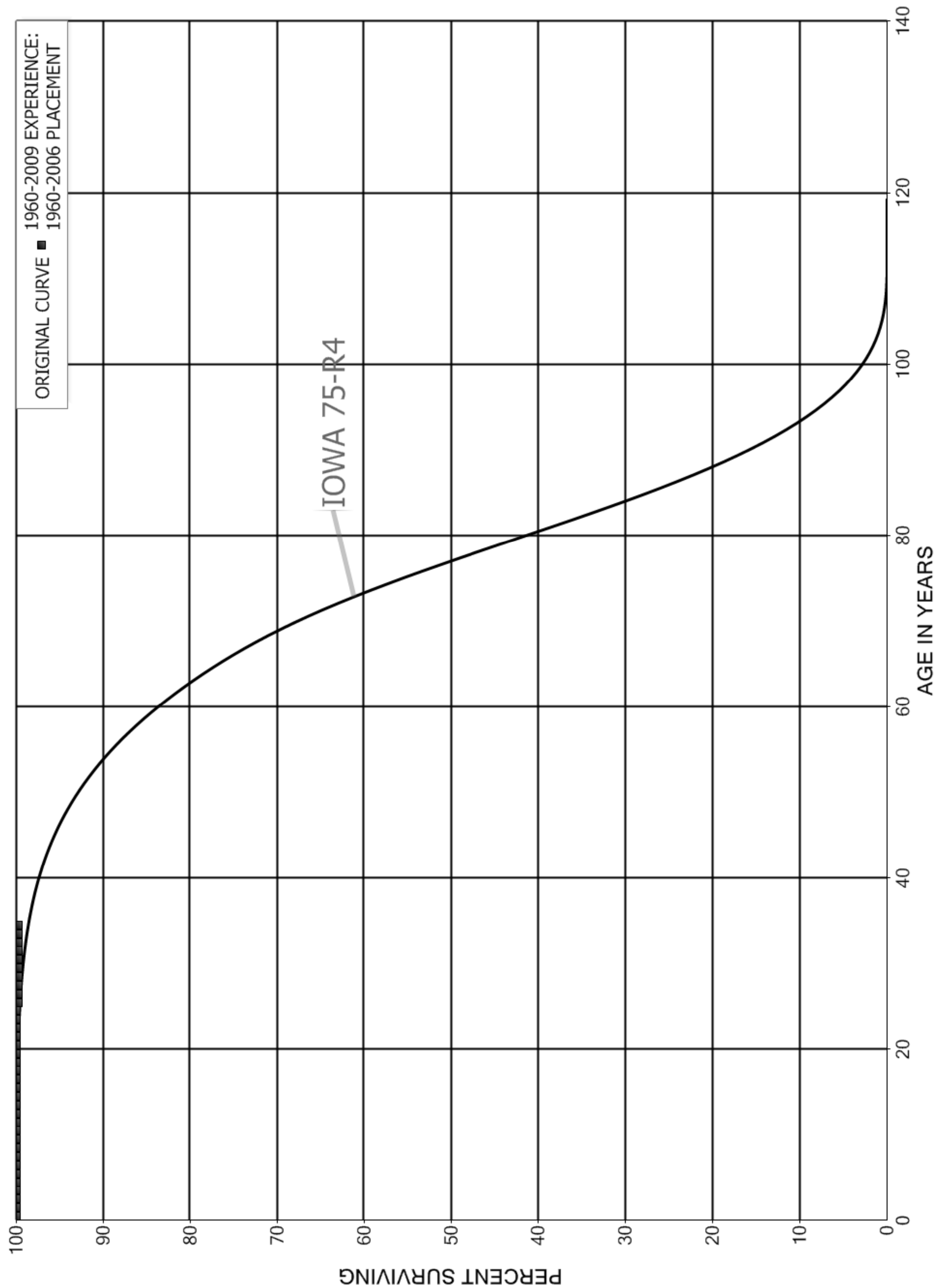
ACCOUNT 368.00 - LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	15,455,865	4,979	0.0003	0.9997	86.23
40.5	15,450,886	224,718	0.0145	0.9855	86.21
41.5	15,226,168	3,660	0.0002	0.9998	84.95
42.5	15,222,508	127,889	0.0084	0.9916	84.93
43.5	15,094,620	156,943	0.0104	0.9896	84.22
44.5	14,937,677	769,187	0.0515	0.9485	83.34
45.5	14,168,490	1,097,501	0.0775	0.9225	79.05
46.5	13,070,989	1,133,967	0.0868	0.9132	72.93
47.5	11,937,022	885,653	0.0742	0.9258	66.60
48.5	11,051,369	1,632,016	0.1477	0.8523	61.66
49.5					52.55

FORTISBC, INC.
ACCOUNT 369.00 - SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



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FORTISBC, INC.

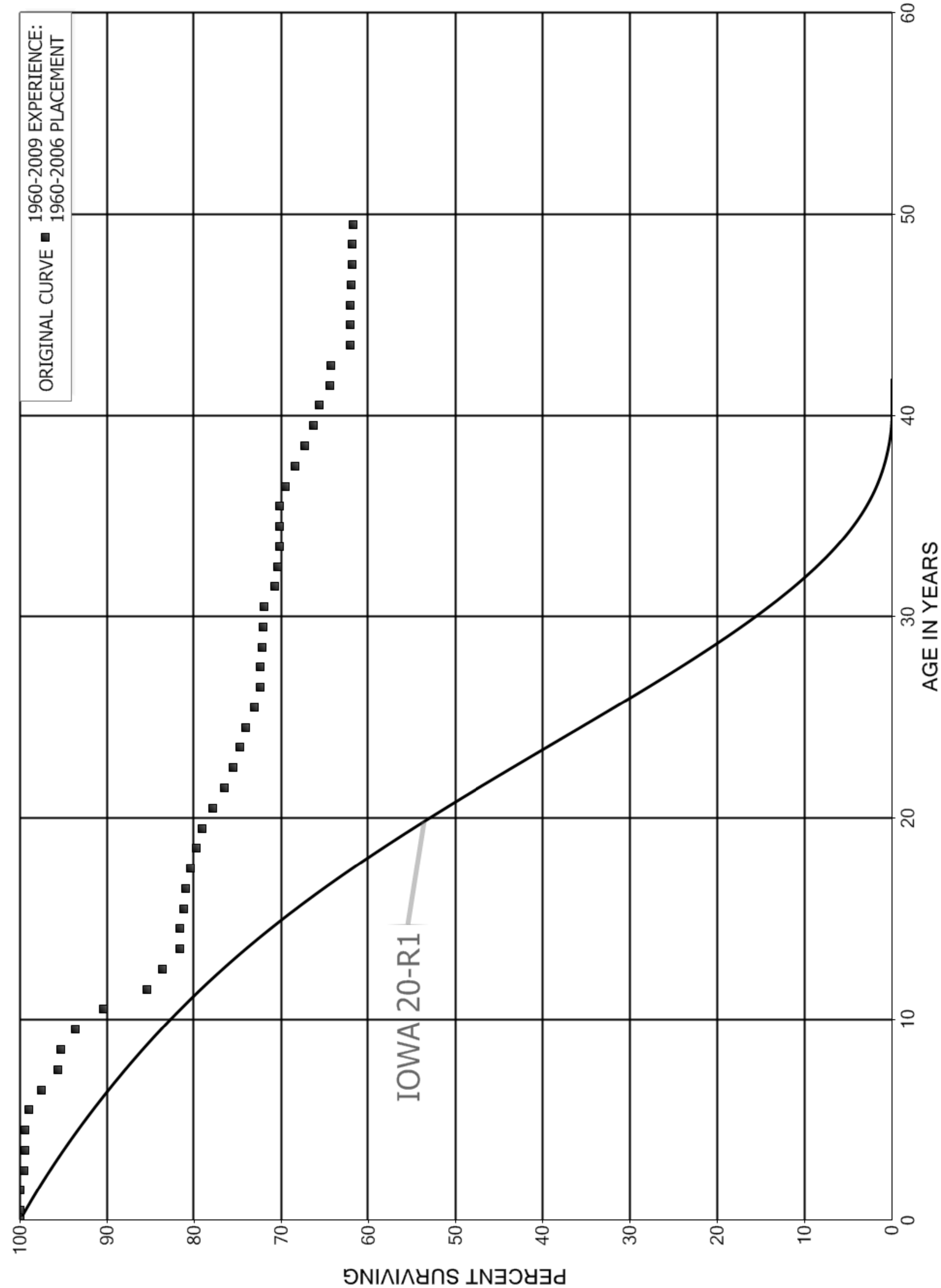
ACCOUNT 369.00 - SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,347,500		0.0000	1.0000	100.00
0.5	7,347,500		0.0000	1.0000	100.00
1.5	7,347,500		0.0000	1.0000	100.00
2.5	7,347,500		0.0000	1.0000	100.00
3.5	6,145,474		0.0000	1.0000	100.00
4.5	6,145,474		0.0000	1.0000	100.00
5.5	6,145,474		0.0000	1.0000	100.00
6.5	6,145,474		0.0000	1.0000	100.00
7.5	6,145,474		0.0000	1.0000	100.00
8.5	6,145,474		0.0000	1.0000	100.00
9.5	6,145,474		0.0000	1.0000	100.00
10.5	6,145,474		0.0000	1.0000	100.00
11.5	6,145,474	2	0.0000	1.0000	100.00
12.5	6,145,472	14	0.0000	1.0000	100.00
13.5	6,145,457	16	0.0000	1.0000	100.00
14.5	6,145,441	30	0.0000	1.0000	100.00
15.5	6,145,411	28	0.0000	1.0000	100.00
16.5	6,145,383	94	0.0000	1.0000	100.00
17.5	6,145,289	186	0.0000	1.0000	100.00
18.5	3,988,053	224	0.0001	0.9999	99.99
19.5	2,526,260	313	0.0001	0.9999	99.99
20.5	2,525,948	2,000	0.0008	0.9992	99.98
21.5	2,523,948	0	0.0000	1.0000	99.90
22.5	2,523,948		0.0000	1.0000	99.90
23.5	2,523,948		0.0000	1.0000	99.90
24.5	2,523,948	3,892	0.0015	0.9985	99.90
25.5	2,520,056	0	0.0000	1.0000	99.74
26.5	2,520,056		0.0000	1.0000	99.74
27.5	2,520,056		0.0000	1.0000	99.74
28.5	1,991,453		0.0000	1.0000	99.74
29.5	1,605,726		0.0000	1.0000	99.74
30.5	1,425,318		0.0000	1.0000	99.74
31.5	1,090,279		0.0000	1.0000	99.74
32.5	684,040		0.0000	1.0000	99.74
33.5	361,390		0.0000	1.0000	99.74
34.5	48,302	48,302	1.0000		99.74
35.5					

FORTISBC, INC.
ACCOUNT 370.00 - METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 370.00 - METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,782,808	1,323	0.0001	0.9999	100.00
0.5	16,781,485	3,903	0.0002	0.9998	99.99
1.5	16,777,582	77,689	0.0046	0.9954	99.97
2.5	16,699,892	15,234	0.0009	0.9991	99.51
3.5	16,253,046	7,659	0.0005	0.9995	99.42
4.5	15,940,806	63,247	0.0040	0.9960	99.37
5.5	15,379,782	220,705	0.0144	0.9856	98.97
6.5	14,426,146	281,231	0.0195	0.9805	97.55
7.5	14,060,676	51,658	0.0037	0.9963	95.65
8.5	13,593,443	242,076	0.0178	0.9822	95.30
9.5	12,424,288	422,546	0.0340	0.9660	93.60
10.5	11,528,776	644,210	0.0559	0.9441	90.42
11.5	10,291,112	217,624	0.0211	0.9789	85.37
12.5	9,515,823	222,793	0.0234	0.9766	83.56
13.5	8,758,934	4,475	0.0005	0.9995	81.61
14.5	8,461,375	35,547	0.0042	0.9958	81.56
15.5	7,959,393	26,734	0.0034	0.9966	81.22
16.5	7,298,367	49,079	0.0067	0.9933	80.95
17.5	6,382,018	57,201	0.0090	0.9910	80.40
18.5	5,899,001	42,216	0.0072	0.9928	79.68
19.5	5,324,763	84,312	0.0158	0.9842	79.11
20.5	4,927,902	87,503	0.0178	0.9822	77.86
21.5	4,626,458	58,862	0.0127	0.9873	76.48
22.5	4,292,231	43,759	0.0102	0.9898	75.51
23.5	4,143,634	35,101	0.0085	0.9915	74.74
24.5	3,945,511	57,571	0.0146	0.9854	74.10
25.5	3,759,672	30,945	0.0082	0.9918	73.02
26.5	3,596,076	2,776	0.0008	0.9992	72.42
27.5	3,391,433	7,586	0.0022	0.9978	72.36
28.5	3,164,644	6,038	0.0019	0.9981	72.20
29.5	2,989,552	5,304	0.0018	0.9982	72.06
30.5	2,921,824	48,347	0.0165	0.9835	71.94
31.5	2,799,823	15,050	0.0054	0.9946	70.75
32.5	2,752,907	6,687	0.0024	0.9976	70.37
33.5	2,746,012		0.0000	1.0000	70.20
34.5	2,746,012		0.0000	1.0000	70.20
35.5	2,746,012	24,948	0.0091	0.9909	70.20
36.5	2,721,064	47,556	0.0175	0.9825	69.56
37.5	2,673,508	40,011	0.0150	0.9850	68.34
38.5	2,633,497	38,580	0.0146	0.9854	67.32

FORTISBC, INC.

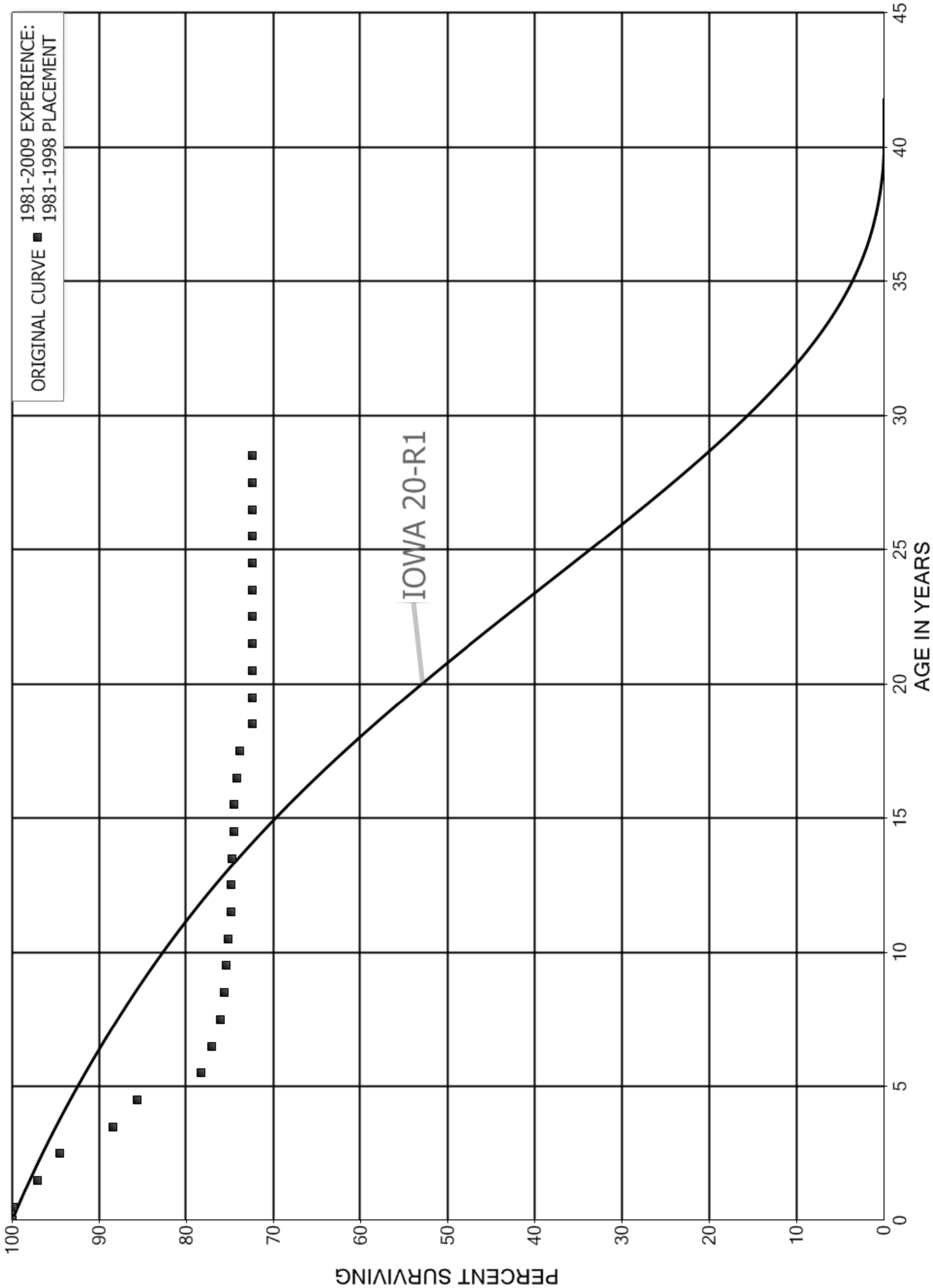
ACCOUNT 370.00 - METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,594,917	27,049	0.0104	0.9896	66.33
40.5	2,567,868	49,457	0.0193	0.9807	65.64
41.5	2,518,411	3,190	0.0013	0.9987	64.38
42.5	2,515,222	87,933	0.0350	0.9650	64.30
43.5	2,427,288		0.0000	1.0000	62.05
44.5	2,427,288	1,399	0.0006	0.9994	62.05
45.5	2,425,889	1,455	0.0006	0.9994	62.01
46.5	2,424,434	3,548	0.0015	0.9985	61.97
47.5	2,420,886		0.0000	1.0000	61.88
48.5	2,420,886	4,100	0.0017	0.9983	61.88
49.5					61.78

FORTISBC, INC.
ACCOUNT 371.00 - INSTALLATIONS ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

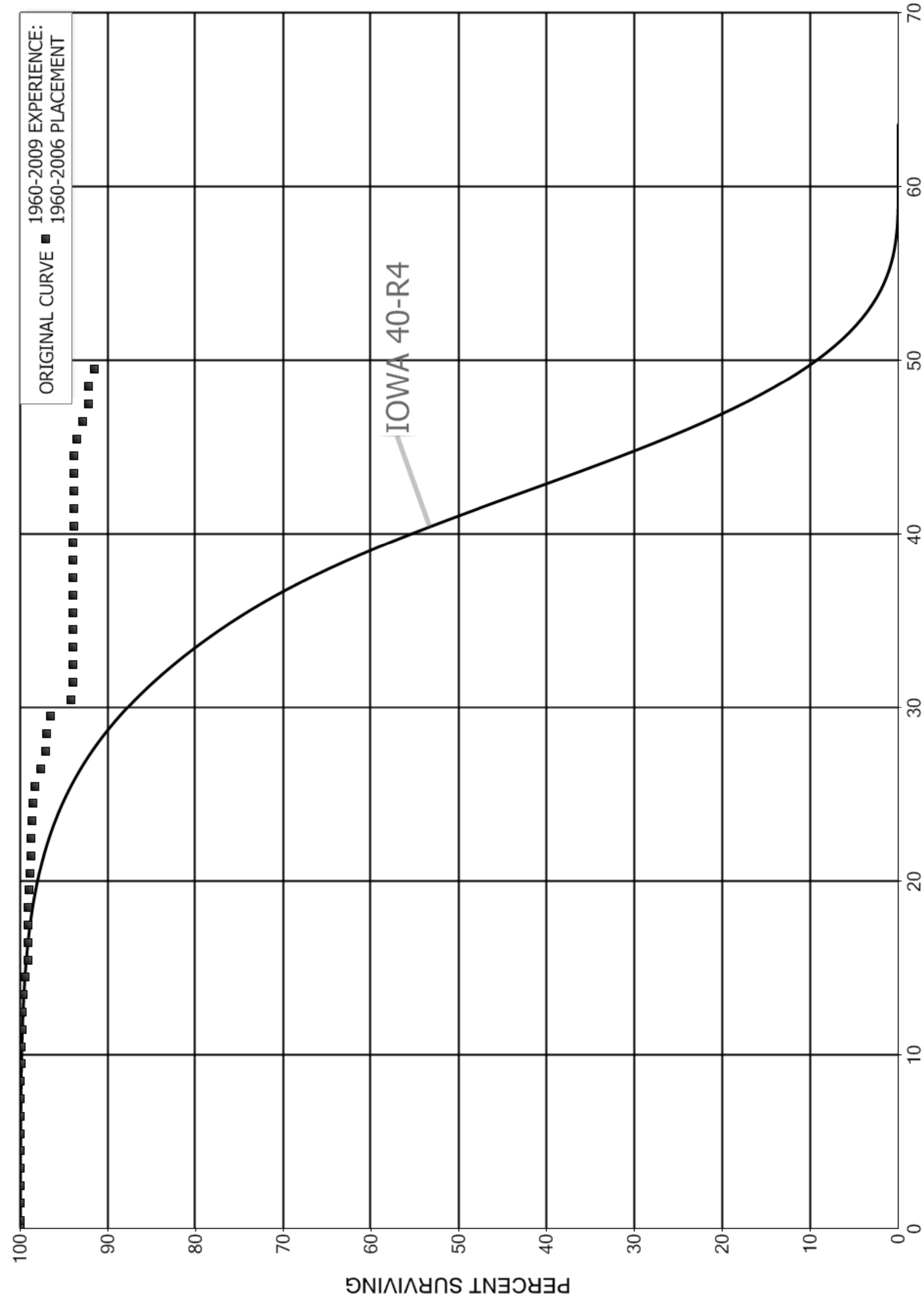
ACCOUNT 371.00 - INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1981-1998 EXPERIENCE BAND 1981-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,275,829	1,571	0.0012	0.9988	100.00
0.5	1,274,258	36,028	0.0283	0.9717	99.88
1.5	1,238,230	33,205	0.0268	0.9732	97.05
2.5	1,205,025	77,568	0.0644	0.9356	94.45
3.5	1,127,457	34,597	0.0307	0.9693	88.37
4.5	1,092,860	93,991	0.0860	0.9140	85.66
5.5	998,869	15,003	0.0150	0.9850	78.29
6.5	983,866	14,006	0.0142	0.9858	77.12
7.5	969,860	5,413	0.0056	0.9944	76.02
8.5	964,447	2,301	0.0024	0.9976	75.59
9.5	962,146	2,661	0.0028	0.9972	75.41
10.5	959,484	4,339	0.0045	0.9955	75.20
11.5	920,192	812	0.0009	0.9991	74.86
12.5	919,379	364	0.0004	0.9996	74.80
13.5	919,016	2,688	0.0029	0.9971	74.77
14.5	913,223	1,037	0.0011	0.9989	74.55
15.5	905,507	3,482	0.0038	0.9962	74.47
16.5	894,233	3,781	0.0042	0.9958	74.18
17.5	263,972	5,150	0.0195	0.9805	73.87
18.5	253,612		0.0000	1.0000	72.42
19.5	248,412		0.0000	1.0000	72.42
20.5	248,412		0.0000	1.0000	72.42
21.5	216,060		0.0000	1.0000	72.42
22.5	190,912		0.0000	1.0000	72.42
23.5	181,931		0.0000	1.0000	72.42
24.5	129,211		0.0000	1.0000	72.42
25.5	113,132		0.0000	1.0000	72.42
26.5	70,614		0.0000	1.0000	72.42
27.5	34,384		0.0000	1.0000	72.42
28.5					72.42

FORTISBC, INC.
ACCOUNT 373.00 - STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 373.00 - STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,981,489		0.0000	1.0000	100.00
0.5	10,981,489	889	0.0001	0.9999	100.00
1.5	10,980,600	80	0.0000	1.0000	99.99
2.5	10,980,520	240	0.0000	1.0000	99.99
3.5	10,834,507	468	0.0000	1.0000	99.99
4.5	10,834,039	1,820	0.0002	0.9998	99.98
5.5	9,945,802	128	0.0000	1.0000	99.97
6.5	8,980,140	1,086	0.0001	0.9999	99.97
7.5	8,979,054	3,797	0.0004	0.9996	99.95
8.5	8,895,297	2,833	0.0003	0.9997	99.91
9.5	8,873,390	5,976	0.0007	0.9993	99.88
10.5	8,821,726	3,337	0.0004	0.9996	99.81
11.5	8,809,472	7,583	0.0009	0.9991	99.78
12.5	8,801,889	9,788	0.0011	0.9989	99.69
13.5	8,770,133	19,554	0.0022	0.9978	99.58
14.5	8,728,328	23,256	0.0027	0.9973	99.36
15.5	8,704,652	2,636	0.0003	0.9997	99.09
16.5	8,698,655	2,354	0.0003	0.9997	99.06
17.5	8,600,595	1,846	0.0002	0.9998	99.04
18.5	8,598,750	5,158	0.0006	0.9994	99.01
19.5	8,593,592	14,433	0.0017	0.9983	98.95
20.5	8,572,321	5,423	0.0006	0.9994	98.79
21.5	8,566,898	4,515	0.0005	0.9995	98.73
22.5	8,562,383	3,046	0.0004	0.9996	98.67
23.5	8,550,677	10,192	0.0012	0.9988	98.64
24.5	8,503,221	22,229	0.0026	0.9974	98.52
25.5	8,445,914	54,935	0.0065	0.9935	98.26
26.5	8,363,390	44,606	0.0053	0.9947	97.62
27.5	8,268,004	13,879	0.0017	0.9983	97.10
28.5	8,194,453	39,132	0.0048	0.9952	96.94
29.5	8,088,224	192,783	0.0238	0.9762	96.48
30.5	7,830,141	18,913	0.0024	0.9976	94.18
31.5	7,704,514	969	0.0001	0.9999	93.95
32.5	7,631,774	1,839	0.0002	0.9998	93.94
33.5	7,524,948	381	0.0001	0.9999	93.92
34.5	7,445,190	127	0.0000	1.0000	93.91
35.5	7,445,063	42	0.0000	1.0000	93.91
36.5	7,445,021		0.0000	1.0000	93.91
37.5	7,445,021	104	0.0000	1.0000	93.91
38.5	7,444,917	1,186	0.0002	0.9998	93.91

FORTISBC, INC.

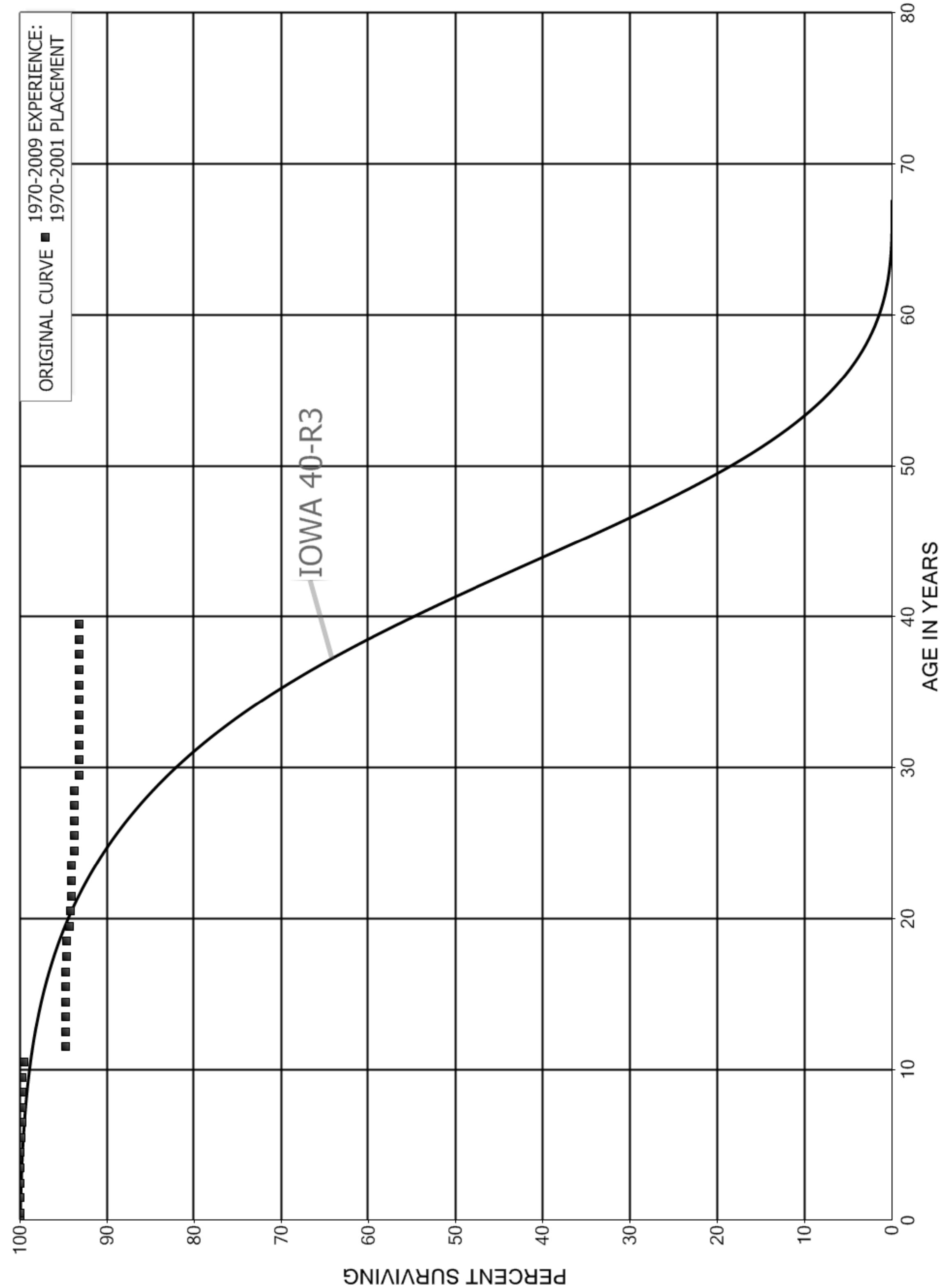
ACCOUNT 373.00 - STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,443,731	2,843	0.0004	0.9996	93.89
40.5	7,440,888	37	0.0000	1.0000	93.86
41.5	7,440,850	12	0.0000	1.0000	93.86
42.5	7,440,838	608	0.0001	0.9999	93.86
43.5	7,440,230	3,539	0.0005	0.9995	93.85
44.5	7,436,691	23,390	0.0031	0.9969	93.80
45.5	7,413,301	49,475	0.0067	0.9933	93.51
46.5	7,363,827	52,676	0.0072	0.9928	92.89
47.5	7,311,151		0.0000	1.0000	92.22
48.5	7,311,151	52,739	0.0072	0.9928	92.22
49.5					91.56

FORTISBC, INC.
ACCOUNT 390.00 - STRUCTURES - FRAME AND IRON
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

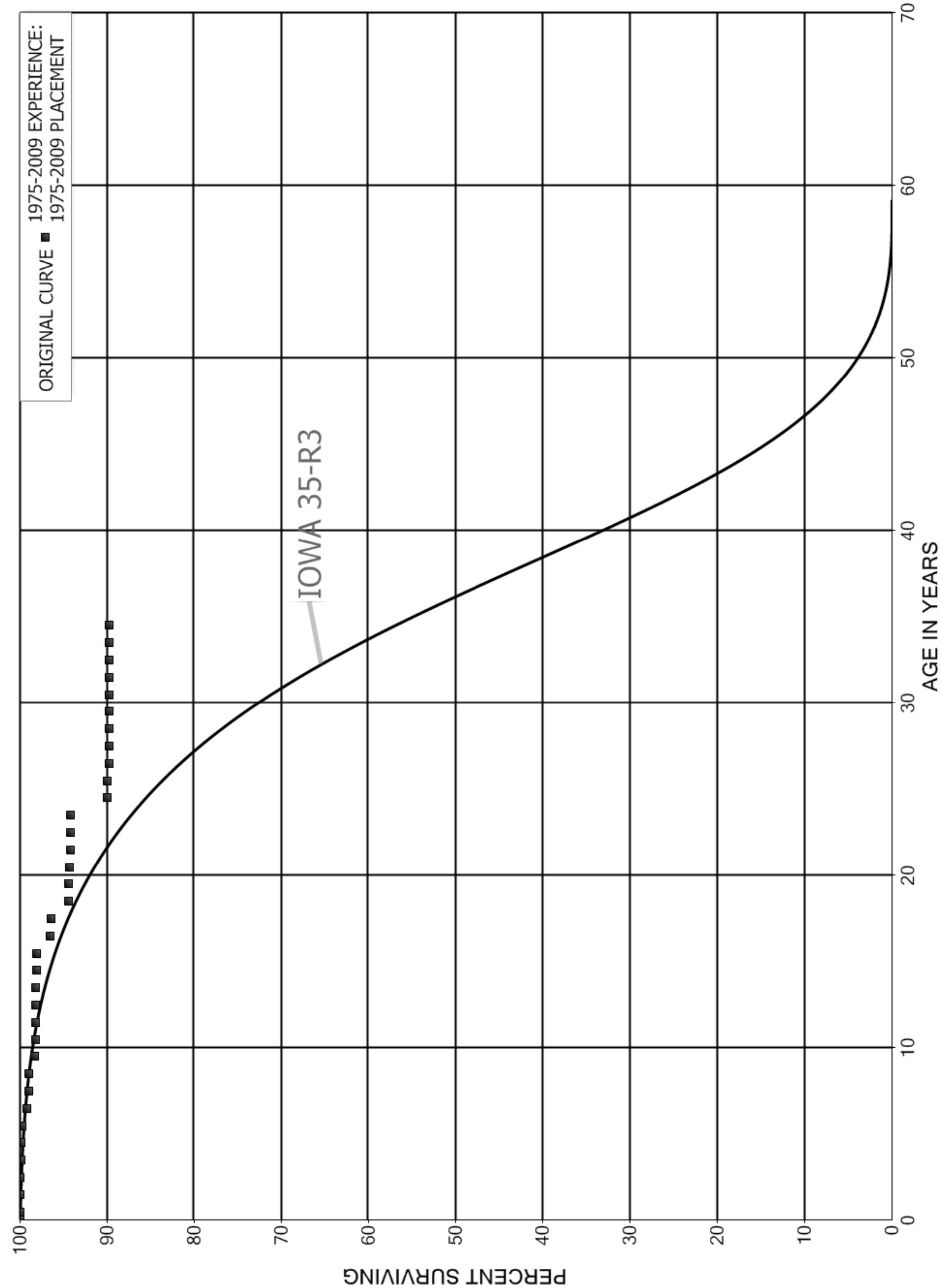
ACCOUNT 390.00 - STRUCTURES - FRAME AND IRON

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2001 EXPERIENCE BAND 1970-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	353,468		0.0000	1.0000	100.00
0.5	353,468		0.0000	1.0000	100.00
1.5	353,468		0.0000	1.0000	100.00
2.5	353,468	1	0.0000	1.0000	100.00
3.5	353,468	1	0.0000	1.0000	100.00
4.5	353,467	437	0.0012	0.9988	100.00
5.5	353,030	440	0.0012	0.9988	99.88
6.5	352,590	12	0.0000	1.0000	99.75
7.5	352,578	0	0.0000	1.0000	99.75
8.5	286,715	4	0.0000	1.0000	99.75
9.5	279,678	608	0.0022	0.9978	99.75
10.5	260,474	12,476	0.0479	0.9521	99.53
11.5	245,793	7	0.0000	1.0000	94.76
12.5	234,081	10	0.0000	1.0000	94.76
13.5	225,742	85	0.0004	0.9996	94.76
14.5	218,763	36	0.0002	0.9998	94.72
15.5	191,373	61	0.0003	0.9997	94.70
16.5	184,216	15	0.0001	0.9999	94.67
17.5	179,233	9	0.0001	0.9999	94.67
18.5	179,224	672	0.0038	0.9962	94.66
19.5	173,267	235	0.0014	0.9986	94.31
20.5	153,101	189	0.0012	0.9988	94.18
21.5	120,336	9	0.0001	0.9999	94.06
22.5	112,256	48	0.0004	0.9996	94.06
23.5	106,688	289	0.0027	0.9973	94.02
24.5	91,263		0.0000	1.0000	93.76
25.5	89,084		0.0000	1.0000	93.76
26.5	84,633	0	0.0000	1.0000	93.76
27.5	83,775		0.0000	1.0000	93.76
28.5	81,133	461	0.0057	0.9943	93.76
29.5	34,576		0.0000	1.0000	93.23
30.5	29,812		0.0000	1.0000	93.23
31.5	15,309		0.0000	1.0000	93.23
32.5	14,804		0.0000	1.0000	93.23
33.5	12,919		0.0000	1.0000	93.23
34.5	4,441		0.0000	1.0000	93.23
35.5	4,441		0.0000	1.0000	93.23
36.5	4,441		0.0000	1.0000	93.23
37.5	4,441		0.0000	1.0000	93.23
38.5	4,441		0.0000	1.0000	93.23
39.5					93.23

FORTISBC, INC.
ACCOUNT 390.10 - STRUCTURES - MASONRY
ORIGINAL AND SMOOTH SURVIVOR CURVES



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FORTISBC, INC.

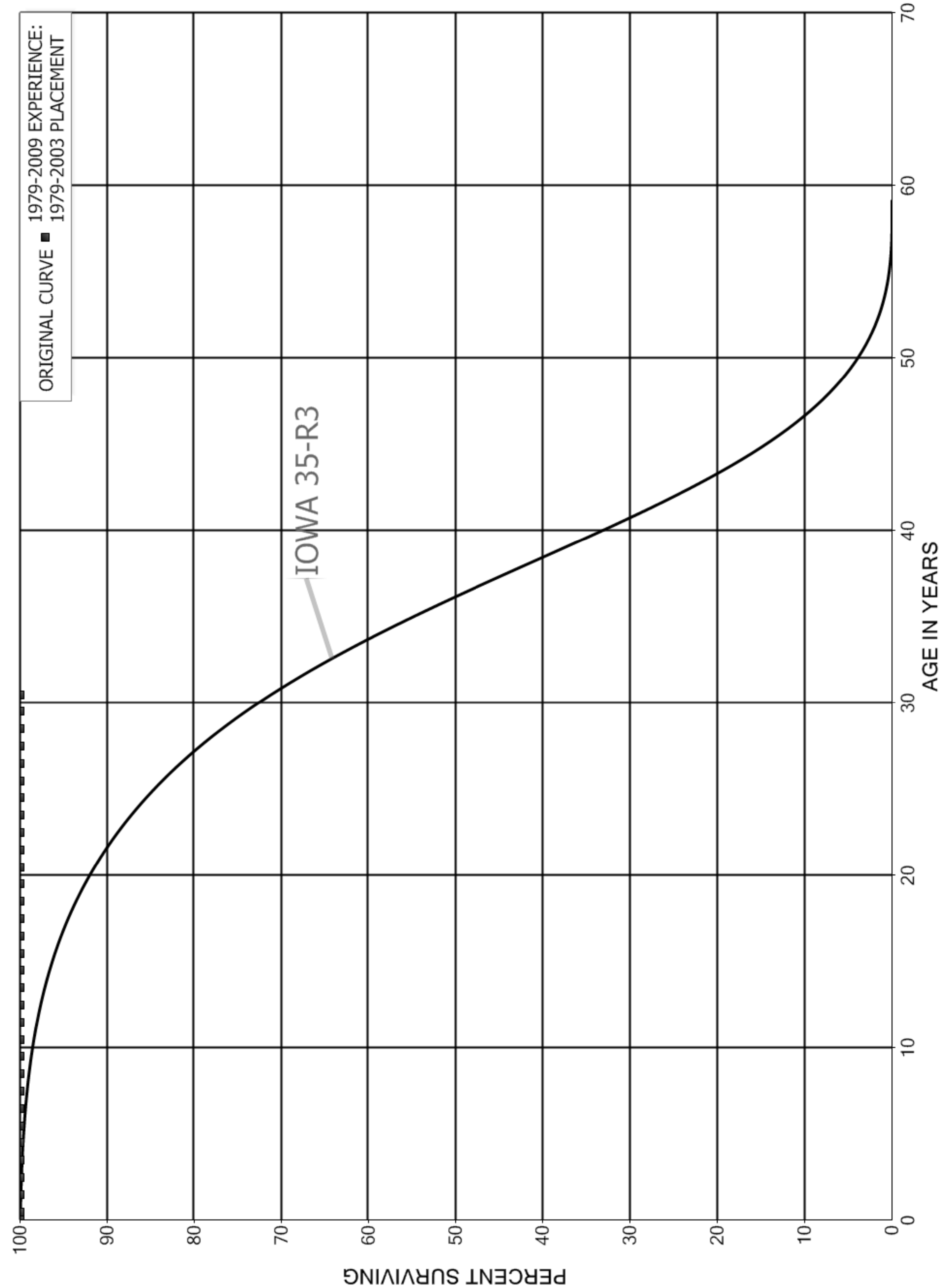
ACCOUNT 390.10 - STRUCTURES - MASONRY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2007 EXPERIENCE BAND 1975-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,687,622		0.0000	1.0000	100.00
0.5	9,687,622		0.0000	1.0000	100.00
1.5	9,687,622	7,600	0.0008	0.9992	100.00
2.5	9,419,740	5,685	0.0006	0.9994	99.92
3.5	9,414,055	7,040	0.0007	0.9993	99.86
4.5	9,407,015	1,319	0.0001	0.9999	99.79
5.5	9,405,696	55,676	0.0059	0.9941	99.77
6.5	9,153,220	24,675	0.0027	0.9973	99.18
7.5	9,128,545		0.0000	1.0000	98.91
8.5	8,895,729	52,773	0.0059	0.9941	98.91
9.5	8,837,689	9,654	0.0011	0.9989	98.33
10.5	8,760,231		0.0000	1.0000	98.22
11.5	8,760,231	1,625	0.0002	0.9998	98.22
12.5	8,758,606	5,595	0.0006	0.9994	98.20
13.5	8,753,011	2,231	0.0003	0.9997	98.14
14.5	8,750,780	735	0.0001	0.9999	98.11
15.5	8,656,917	139,958	0.0162	0.9838	98.11
16.5	8,224,094	8,181	0.0010	0.9990	96.52
17.5	8,064,781	170,388	0.0211	0.9789	96.42
18.5	7,754,518	3,804	0.0005	0.9995	94.39
19.5	7,750,714	4,316	0.0006	0.9994	94.34
20.5	7,367,140	6,650	0.0009	0.9991	94.29
21.5	6,613,987	4,393	0.0007	0.9993	94.20
22.5	5,347,460		0.0000	1.0000	94.14
23.5	5,270,903	232,497	0.0441	0.9559	94.14
24.5	3,327,871		0.0000	1.0000	89.99
25.5	3,327,871	11,000	0.0033	0.9967	89.99
26.5	2,654,218		0.0000	1.0000	89.69
27.5	2,654,218		0.0000	1.0000	89.69
28.5	2,654,218		0.0000	1.0000	89.69
29.5	2,654,218		0.0000	1.0000	89.69
30.5	594,921		0.0000	1.0000	89.69
31.5	594,921		0.0000	1.0000	89.69
32.5	594,921		0.0000	1.0000	89.69
33.5	496,561		0.0000	1.0000	89.69
34.5					89.69

FORTISBC, INC.
ACCOUNT 390.20 - OPERATIONS BUILDINGS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

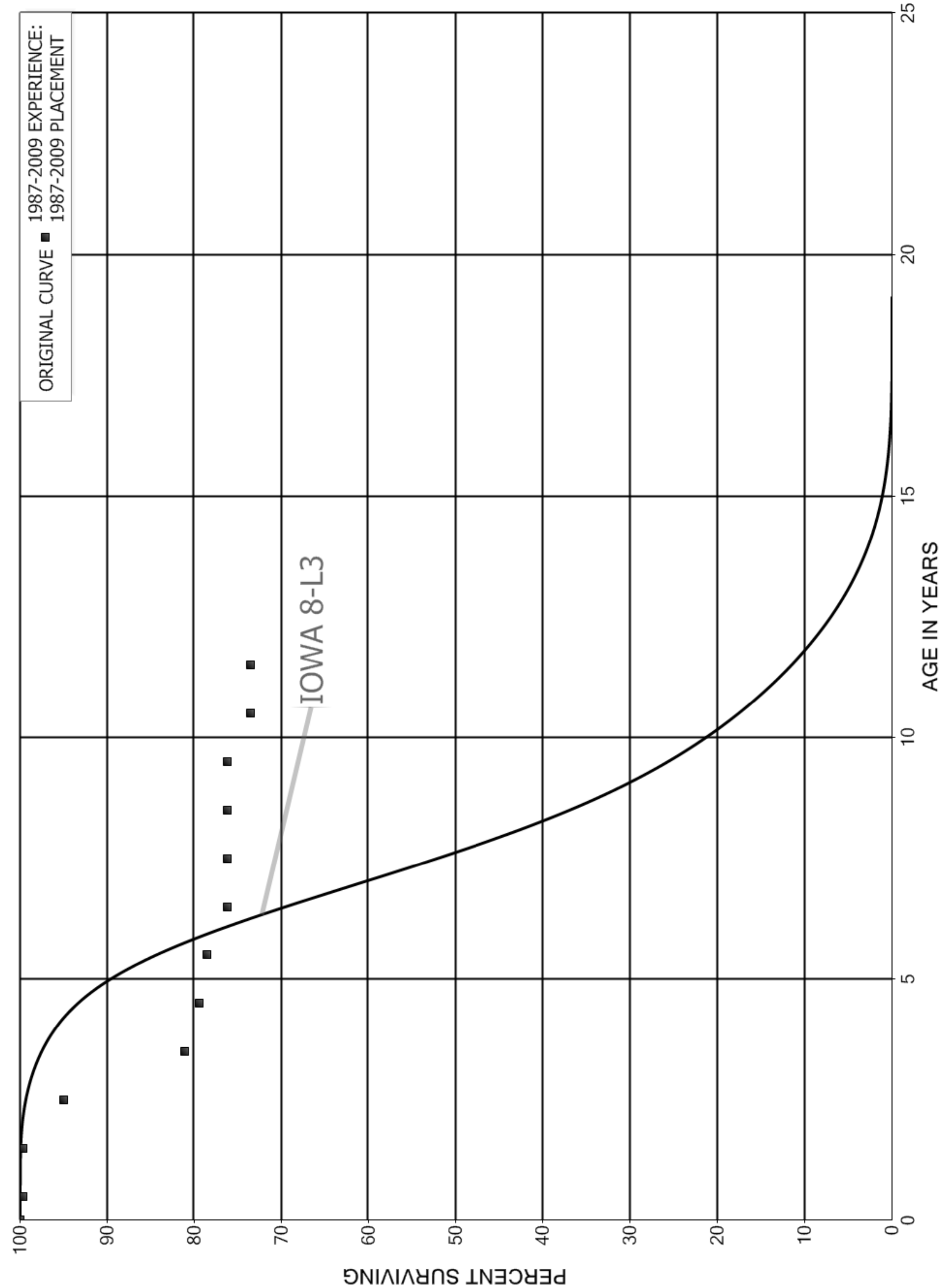
ACCOUNT 390.20 - OPERATIONS BUILDINGS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1979-2003 EXPERIENCE BAND 1979-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,750,128		0.0000	1.0000	100.00
0.5	12,750,128		0.0000	1.0000	100.00
1.5	12,750,128		0.0000	1.0000	100.00
2.5	12,750,128		0.0000	1.0000	100.00
3.5	12,750,128		0.0000	1.0000	100.00
4.5	12,750,128		0.0000	1.0000	100.00
5.5	12,750,128		0.0000	1.0000	100.00
6.5	7,816,293		0.0000	1.0000	100.00
7.5	7,816,293		0.0000	1.0000	100.00
8.5	7,816,293		0.0000	1.0000	100.00
9.5	7,816,293		0.0000	1.0000	100.00
10.5	7,816,293		0.0000	1.0000	100.00
11.5	7,816,293		0.0000	1.0000	100.00
12.5	7,816,293		0.0000	1.0000	100.00
13.5	7,816,293		0.0000	1.0000	100.00
14.5	7,816,293		0.0000	1.0000	100.00
15.5	7,816,293		0.0000	1.0000	100.00
16.5	7,816,293		0.0000	1.0000	100.00
17.5	7,816,293		0.0000	1.0000	100.00
18.5	7,816,293		0.0000	1.0000	100.00
19.5	7,816,293		0.0000	1.0000	100.00
20.5	7,816,293		0.0000	1.0000	100.00
21.5	7,816,293		0.0000	1.0000	100.00
22.5	7,816,293		0.0000	1.0000	100.00
23.5	7,816,293		0.0000	1.0000	100.00
24.5	7,816,293		0.0000	1.0000	100.00
25.5	7,816,293		0.0000	1.0000	100.00
26.5	7,816,293		0.0000	1.0000	100.00
27.5	7,816,293		0.0000	1.0000	100.00
28.5	7,816,293		0.0000	1.0000	100.00
29.5	7,816,293		0.0000	1.0000	100.00
30.5					100.00

FORTISBC, INC.
ACCOUNT 392.10 - LIGHT DUTY VEHICLES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

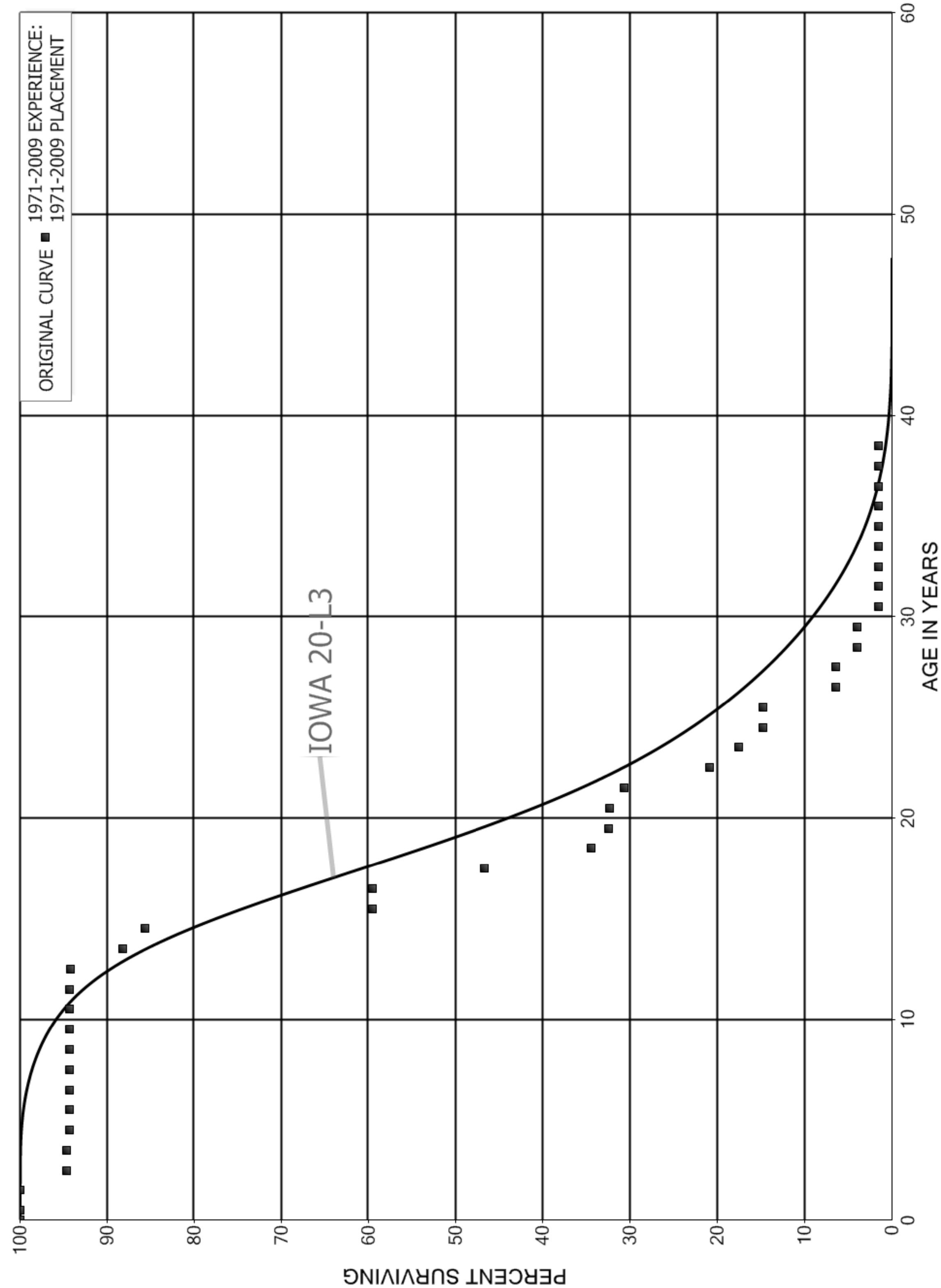
ACCOUNT 392.10 - LIGHT DUTY VEHICLES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1987-2009 EXPERIENCE BAND 1987-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	18,109,498	60,011	0.0033	0.9967	100.00
0.5	17,791,780		0.0000	1.0000	99.67
1.5	16,756,168	798,400	0.0476	0.9524	99.67
2.5	14,758,096	2,152,260	0.1458	0.8542	94.92
3.5	10,401,683	217,571	0.0209	0.9791	81.08
4.5	8,516,831	93,530	0.0110	0.9890	79.38
5.5	8,336,194	249,695	0.0300	0.9700	78.51
6.5	8,071,011		0.0000	1.0000	76.16
7.5	8,071,011		0.0000	1.0000	76.16
8.5	8,071,011		0.0000	1.0000	76.16
9.5	8,071,011	280,820	0.0348	0.9652	76.16
10.5	7,790,191		0.0000	1.0000	73.51
11.5	7,790,191	1,403,820	0.1802	0.8198	73.51
12.5	6,386,371	3,384,920	0.5300	0.4700	60.26
13.5	2,978,261	185,250	0.0622	0.9378	28.32
14.5	2,591,216	586,030	0.2262	0.7738	26.56
15.5	1,981,644	797,129	0.4023	0.5977	20.55
16.5	1,184,515	369,100	0.3116	0.6884	12.29
17.5	815,415	392,090	0.4808	0.5192	8.46
18.5	423,325	187,890	0.4438	0.5562	4.39
19.5	207,220	1,290	0.0062	0.9938	2.44
20.5	183,140	183,140	1.0000		2.43
21.5					

FORTISBC, INC.
ACCOUNT 392.20 - HEAVY DUTY VEHICLES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC, INC.

ACCOUNT 392.20 - HEAVY DUTY VEHICLES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2009 EXPERIENCE BAND 1971-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	26,443,918		0.0000	1.0000	100.00
0.5	24,636,909		0.0000	1.0000	100.00
1.5	23,967,842	1,295,930	0.0541	0.9459	100.00
2.5	19,485,777		0.0000	1.0000	94.59
3.5	18,410,382	59,440	0.0032	0.9968	94.59
4.5	17,592,744		0.0000	1.0000	94.29
5.5	17,418,199		0.0000	1.0000	94.29
6.5	17,294,400		0.0000	1.0000	94.29
7.5	16,989,571		0.0000	1.0000	94.29
8.5	16,989,571		0.0000	1.0000	94.29
9.5	16,911,216	9,809	0.0006	0.9994	94.29
10.5	16,853,911		0.0000	1.0000	94.23
11.5	16,853,911	11,340	0.0007	0.9993	94.23
12.5	16,842,571	1,078,584	0.0640	0.9360	94.17
13.5	15,700,921	452,470	0.0288	0.9712	88.14
14.5	14,856,974	4,537,200	0.3054	0.6946	85.60
15.5	9,799,168		0.0000	1.0000	59.46
16.5	9,749,781	2,109,361	0.2163	0.7837	59.46
17.5	7,301,630	1,905,740	0.2610	0.7390	46.59
18.5	5,371,697	319,589	0.0595	0.9405	34.43
19.5	4,568,118	20,392	0.0045	0.9955	32.38
20.5	4,519,164	224,969	0.0498	0.9502	32.24
21.5	4,294,195	1,380,280	0.3214	0.6786	30.63
22.5	2,705,693	427,170	0.1579	0.8421	20.79
23.5	2,278,523	361,340	0.1586	0.8414	17.51
24.5	1,797,029	7,000	0.0039	0.9961	14.73
25.5	1,753,311	991,018	0.5652	0.4348	14.67
26.5	727,595		0.0000	1.0000	6.38
27.5	675,254	252,426	0.3738	0.6262	6.38
28.5	422,825		0.0000	1.0000	3.99
29.5	344,155	214,170	0.6223	0.3777	3.99
30.5	118,280		0.0000	1.0000	1.51
31.5	61,170		0.0000	1.0000	1.51
32.5	61,170		0.0000	1.0000	1.51
33.5	61,170		0.0000	1.0000	1.51
34.5	61,170		0.0000	1.0000	1.51
35.5	61,170		0.0000	1.0000	1.51
36.5	61,170		0.0000	1.0000	1.51
37.5	17,435		0.0000	1.0000	1.51
38.5					1.51

PART V. NET SALVAGE STATISTICS

FORTISBC, INC.

ACCOUNT 331.00 - STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	14,776		0		0		0
1996							
1997							
1998							
1999							
2000		10				10-	
2001							
2002							
2003							
2004	40,943	409	1		0	409-	1-
2005	51,854	455	1		0	455-	1-
2006	3,832	45	1		0	45-	1-
2007	10,530	73	1		0	73-	1-
2008		372				372-	
2009		34,323				34,323-	
TOTAL	121,935	35,689	29		0	35,689-	29-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	4,925		0		0		0
96-98							
97-99							
98-00		3				3-	
99-01		3				3-	
00-02		3				3-	
01-03							
02-04	13,648	136	1		0	136-	1-
03-05	30,932	288	1		0	288-	1-
04-06	32,210	303	1		0	303-	1-
05-07	22,072	191	1		0	191-	1-
06-08	4,787	164	3		0	164-	3-
07-09	3,510	11,589	330		0	11,589-	330-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
05-09	13,243	7,054	53		0	7,054-	53-

FORTISBC, INC.

ACCOUNT 332.00 - RESERVOIRS, DAMS, AND WATERWAYS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003							
2004	68,452	685	1		0	685-	1-
2005	369,177	655	0		0	655-	0
2006	3,015	806	27		0	806-	27-
2007	76,239	1,474	2		0	1,474-	2-
2008	4,551	47	1		0	47-	1-
2009	19,693	213,012			0	213,012-	
TOTAL	541,127	216,680	40		0	216,680-	40-
THREE-YEAR MOVING AVERAGES							
03-05	145,876	446	0		0	446-	0
04-06	146,881	715	0		0	715-	0
05-07	149,477	978	1		0	978-	1-
06-08	27,935	776	3		0	776-	3-
07-09	33,494	71,511	214		0	71,511-	214-
FIVE-YEAR AVERAGE							
05-09	94,535	43,199	46		0	43,199-	46-

FORTISBC, INC.

ACCOUNT 333.00 - WATER WHEELS, TURBINES, AND GENERATORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995		149				149-	
1996							
1997							
1998							
1999		433			0	433-	
2000	33,568	563	2		0	563-	2-
2001		17				17-	
2002							
2003	362,133	5	0		0	5-	0
2004	170,821	4,290	3		0	4,290-	3-
2005		3,442				3,442-	
2006	1,083	138	13		0	138-	13-
2007	367,027	3,509	1		0	3,509-	1-
2008	181,067	4,722	3		0	4,722-	3-
2009	368,480	491,636	133		0	491,636-	133-
TOTAL	1,484,179	508,904	34		0	508,904-	34-
THREE-YEAR MOVING AVERAGES							
95-97		50				50-	
96-98							
97-99		144				144-	
98-00	11,189	332	3		0	332-	3-
99-01	11,189	338	3		0	338-	3-
00-02	11,189	193	2		0	193-	2-
01-03	120,711	7	0		0	7-	0
02-04	177,651	1,432	1		0	1,432-	1-
03-05	177,651	2,579	1		0	2,579-	1-
04-06	57,301	2,623	5		0	2,623-	5-
05-07	122,703	2,363	2		0	2,363-	2-
06-08	183,059	2,790	2		0	2,790-	2-
07-09	305,525	166,623	55		0	166,623-	55-
FIVE-YEAR AVERAGE							
05-09	183,531	100,689	55		0	100,689-	55-

FORTISBC, INC.

ACCOUNT 334.00 - ACCESSORY ELECTRICAL EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1999		440				440-	
2000		653				653-	
2001							
2002		473				473-	
2003	188,915	2	0		0	2-	0
2004	69,020	690	1		0	690-	1-
2005	70,164	2,527	4		0	2,527-	4-
2006	37,818	247	1		0	247-	1-
2007	132,922	1,073	1		0	1,073-	1-
2008	93,009	1,160	1		0	1,160-	1-
2009	194,348	209,855	108		0	209,855-	108-
TOTAL	786,198	217,120	28		0	217,120-	28-
THREE-YEAR MOVING AVERAGES							
99-01		364				364-	
00-02		375				375-	
01-03	62,972	158	0		0	158-	0
02-04	85,979	388	0		0	388-	0
03-05	109,366	1,073	1		0	1,073-	1-
04-06	59,001	1,155	2		0	1,155-	2-
05-07	80,302	1,283	2		0	1,283-	2-
06-08	87,917	827	1		0	827-	1-
07-09	140,093	70,696	50		0	70,696-	50-
FIVE-YEAR AVERAGE							
05-09	105,652	42,972	41		0	42,972-	41-

FORTISBC, INC.

ACCOUNT 335.00 - OTHER POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	57,465	598	1		0	598-	1-
2001							
2002							
2003							
2004							
2005	76,417	84	0		0	84-	0
2006							
2007	30,528	227	1		0	227-	1-
2008	30,120	137	0		0	137-	0
2009	90,985		0		0		0
TOTAL	285,515	1,046	0		0	1,046-	0
THREE-YEAR MOVING AVERAGES							
00-02	19,155	199	1		0	199-	1-
01-03							
02-04							
03-05	25,472	28	0		0	28-	0
04-06	25,472	28	0		0	28-	0
05-07	35,648	104	0		0	104-	0
06-08	20,216	121	1		0	121-	1-
07-09	50,544	121	0		0	121-	0
FIVE-YEAR AVERAGE							
05-09	45,610	90	0		0	90-	0

FORTISBC, INC.

ACCOUNT 350.10 - LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	202,938	2	0		0	2-	0
2004	24,931	258	1		0	258-	1-
2005							
2006							
2007							
2008							
2009							
TOTAL	227,869	260	0		0	260-	0
THREE-YEAR MOVING AVERAGES							
03-05	75,956	87	0		0	87-	0
04-06	8,310	86	1		0	86-	1-
05-07							
06-08							
07-09							
FIVE-YEAR AVERAGE							
05-09							

FORTISBC, INC.

ACCOUNT 353.00 - SUBSTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1996	7,794		0		0		0
1997							
1998		1,886				1,886-	
1999	50,703	68	0		0	68-	0
2000		382				382-	
2001		173				173-	
2002							
2003							
2004		901				901-	
2005		795				795-	
2006	496,251	2,350	0		0	2,350-	0
2007	75,512	3,370	4		0	3,370-	4-
2008	49,236	5,005	10		0	5,005-	10-
2009	21,849	242,754			0	242,754-	
TOTAL	701,345	257,684	37		0	257,684-	37-
THREE-YEAR MOVING AVERAGES							
96-98	2,598	629	24		0	629-	24-
97-99	16,901	651	4		0	651-	4-
98-00	16,901	779	5		0	779-	5-
99-01	16,901	208	1		0	208-	1-
00-02		185				185-	
01-03		58				58-	
02-04		300				300-	
03-05		565				565-	
04-06	165,417	1,349	1		0	1,349-	1-
05-07	190,587	2,172	1		0	2,172-	1-
06-08	207,000	3,575	2		0	3,575-	2-
07-09	48,866	83,710	171		0	83,710-	171-
FIVE-YEAR AVERAGE							
05-09	128,570	50,855	40		0	50,855-	40-

FORTISBC, INC.

ACCOUNT 355.00 - POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	99,949	974	1		0	974-	1-
1996	213,287	2,079	1		0	2,079-	1-
1997		883-				883	
1998							
1999	6,579	3,462	53		0	3,462-	53-
2000	100,351	1,251	1		0	1,251-	1-
2001	2,512	25	1		0	25-	1-
2002		454				454-	
2003	1,091,033	20	0		0	20-	0
2004	223,141	15,852	7		0	15,852-	7-
2005	64,253	3,428-	5-		0	3,428	5
2006	49,637	3,571	7		0	3,571-	7-
2007	2,154	2,282	106		0	2,282-	106-
2008	15,154	2,508	17		0	2,508-	17-
2009	24,891	330,850			0	330,850-	
TOTAL	1,892,939	359,016	19		0	359,016-	19-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	104,412	723	1		0	723-	1-
96-98	71,096	399	1		0	399-	1-
97-99	2,193	860	39		0	860-	39-
98-00	35,643	1,571	4		0	1,571-	4-
99-01	36,480	1,579	4		0	1,579-	4-
00-02	34,288	577	2		0	577-	2-
01-03	364,515	166	0		0	166-	0
02-04	438,058	5,442	1		0	5,442-	1-
03-05	459,475	4,148	1		0	4,148-	1-
04-06	112,343	5,332	5		0	5,332-	5-
05-07	38,681	808	2		0	808-	2-
06-08	22,315	2,787	12		0	2,787-	12-
07-09	14,066	111,880	795		0	111,880-	795-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
05-09	31,218	67,156	215		0	67,156-	215-

FORTISBC, INC.

ACCOUNT 356.00 - CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	13,192	125	1		0	125-	1-
1996	393,558	3,731	1		0	3,731-	1-
1997	124,398-	122-	0		0	122	0
1998			0		0		0
1999		3,619				3,619-	
2000	103,152	1,250	1		0	1,250-	1-
2001	6,887	69	1		0	69-	1-
2002							
2003	855,508	9	0		0	9-	0
2004	211,195	4,055	2		0	4,055-	2-
2005		4,976				4,976-	
2006		3,571				3,571-	
2007		2,069				2,069-	
2008		2,508				2,508-	
2009		419,432				419,432-	
TOTAL	1,459,096	445,291	31		0	445,291-	31-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	94,118	1,245	1		0	1,245-	1-
96-98	89,720	1,203	1		0	1,203-	1-
97-99	41,466-	1,166	3-		0	1,166-	3
98-00	34,384	1,623	5		0	1,623-	5-
99-01	36,680	1,646	4		0	1,646-	4-
00-02	36,680	440	1		0	440-	1-
01-03	287,465	26	0		0	26-	0
02-04	355,568	1,355	0		0	1,355-	0
03-05	355,568	3,013	1		0	3,013-	1-
04-06	70,398	4,201	6		0	4,201-	6-
05-07		3,538				3,538-	
06-08		2,716				2,716-	
07-09		141,336				141,336-	

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
05-09		86,511				86,511-	

FORTISBC, INC.

ACCOUNT 362.00 - SUBSTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995		3,074			0	3,074-	
1996	330,483	3,403	1		0	3,403-	1-
1997			0		0		0
1998	146,294		0		0		0
1999			0		0		0
2000	15,208	115	1		0	115-	1-
2001	17,841	307	2		0	307-	2-
2002		83				83-	
2003	383,051	4	0		0	4-	0
2004	161,630	1,877	1		0	1,877-	1-
2005		328				328-	
2006	780,412	768	0		0	768-	0
2007	233,118	2,769	1		0	2,769-	1-
2008	73,108	1,302	2		0	1,302-	2-
2009	2,018,319	77,851	4		0	77,851-	4-
TOTAL	4,159,465	91,883	2		0	91,883-	2-
THREE-YEAR MOVING AVERAGES							
95-97	110,161	2,159	2		0	2,159-	2-
96-98	158,926	1,134	1		0	1,134-	1-
97-99	48,765		0		0		0
98-00	53,834	38	0		0	38-	0
99-01	11,016	141	1		0	141-	1-
00-02	11,016	169	2		0	169-	2-
01-03	133,631	132	0		0	132-	0
02-04	181,560	655	0		0	655-	0
03-05	181,560	737	0		0	737-	0
04-06	314,014	991	0		0	991-	0
05-07	337,844	1,288	0		0	1,288-	0
06-08	362,213	1,613	0		0	1,613-	0
07-09	774,849	27,307	4		0	27,307-	4-
FIVE-YEAR AVERAGE							
05-09	620,992	16,604	3		0	16,604-	3-

FORTISBC, INC.

ACCOUNT 364.00 - POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	358,733	4,178	1		0	4,178-	1-
1996	249,180	83	0		0	83-	0
1997	361,979	865	0		0	865-	0
1998	261,380	1,154	0		0	1,154-	0
1999	102,575	2,893	3		0	2,893-	3-
2000	105,334	3,773	4		0	3,773-	4-
2001	87,504	3,368	4		0	3,368-	4-
2002		5,836				5,836-	
2003		2				2-	
2004	152,450	4,070	3		0	4,070-	3-
2005	124,134	12	0		0	12-	0
2006	249,103	4	0		0	4-	0
2007	285,089	70-	0		0	70	0
2008	354,093	56-	0		0	56	0
2009	433,826	899,583	207		0	899,583-	207-
TOTAL	3,125,379	925,695	30		0	925,695-	30-

THREE-YEAR MOVING AVERAGES

95-97	323,297	1,709	1		0	1,709-	1-
96-98	290,846	701	0		0	701-	0
97-99	241,978	1,637	1		0	1,637-	1-
98-00	156,430	2,607	2		0	2,607-	2-
99-01	98,471	3,345	3		0	3,345-	3-
00-02	64,279	4,326	7		0	4,326-	7-
01-03	29,168	3,068	11		0	3,068-	11-
02-04	50,817	3,302	6		0	3,302-	6-
03-05	92,194	1,361	1		0	1,361-	1-
04-06	175,229	1,362	1		0	1,362-	1-
05-07	219,442	18-	0		0	18	0
06-08	296,095	40-	0		0	40	0
07-09	357,669	299,819	84		0	299,819-	84-

FIVE-YEAR AVERAGE

05-09	289,249	179,895	62		0	179,895-	62-

FORTISBC, INC.

ACCOUNT 365.00 - CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	825,623	1,670	0		0	1,670-	0
1996	193,306	3,212-	2-		0	3,212	2
1997	336,433	5,100	2		0	5,100-	2-
1998	216,234	1,261	1		0	1,261-	1-
1999		2,090				2,090-	
2000	93,238	3,744	4		0	3,744-	4-
2001	44,968	3,034	7		0	3,034-	7-
2002		368-				368	
2003	75,543	1	0		0	1-	0
2004	113,231	5,802	5		0	5,802-	5-
2005	273,643	296-	0		0	296	0
2006	417,711	1,269-	0		0	1,269	0
2007	428,815	274-	0		0	274	0
2008	587,763		0		0		0
2009	708,815	1,393,766	197		0	1,393,766-	197-
TOTAL	4,315,324	1,411,048	33		0	1,411,048-	33-
THREE-YEAR MOVING AVERAGES							
95-97	451,787	1,186	0		0	1,186-	0
96-98	248,658	1,050	0		0	1,050-	0
97-99	184,222	2,817	2		0	2,817-	2-
98-00	103,157	2,365	2		0	2,365-	2-
99-01	46,069	2,956	6		0	2,956-	6-
00-02	46,069	2,136	5		0	2,136-	5-
01-03	40,170	889	2		0	889-	2-
02-04	62,925	1,812	3		0	1,812-	3-
03-05	154,139	1,836	1		0	1,836-	1-
04-06	268,195	1,412	1		0	1,412-	1-
05-07	373,390	613-	0		0	613	0
06-08	478,097	514-	0		0	514	0
07-09	575,131	464,497	81		0	464,497-	81-
FIVE-YEAR AVERAGE							
05-09	483,350	278,385	58		0	278,385-	58-

FORTISBC, INC.

ACCOUNT 368.00 - LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	5,468	492	9		0	492-	9-
1996		85-				85	
1997	146,975		0		0		0
1998							
1999	127,125	2,340	2		0	2,340-	2-
2000		308				308-	
2001	227,756	2,407	1		0	2,407-	1-
2002		2,017				2,017-	
2003	234,683	3	0		0	3-	0
2004	481,295	7,569	2		0	7,569-	2-
2005	577,784	277	0		0	277-	0
2006	942,950	1,308	0		0	1,308-	0
2007	1,026,299	3,020	0		0	3,020-	0
2008	1,461,654	2,048	0		0	2,048-	0
2009	1,632,016	737,628	45		0	737,628-	45-
TOTAL	6,864,004	759,330	11		0	759,330-	11-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	50,815	136	0		0	136-	0
96-98	48,992	28-	0		0	28	0
97-99	91,367	780	1		0	780-	1-
98-00	42,375	883	2		0	883-	2-
99-01	118,294	1,685	1		0	1,685-	1-
00-02	75,919	1,577	2		0	1,577-	2-
01-03	154,146	1,476	1		0	1,476-	1-
02-04	238,659	3,196	1		0	3,196-	1-
03-05	431,254	2,616	1		0	2,616-	1-
04-06	667,343	3,051	0		0	3,051-	0
05-07	849,011	1,535	0		0	1,535-	0
06-08	1,143,634	2,125	0		0	2,125-	0
07-09	1,373,323	247,565	18		0	247,565-	18-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
05-09	1,128,140	148,856	13		0	148,856-	13-

FORTISBC, INC.

ACCOUNT 370.00 - METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	2,804,975	29	0		0	29-	0
2004	59	105-	178-		0	105	178
2005	1,399	1,234-	88-		0	1,234	88
2006	1,455	769	53		0	769-	53-
2007	3,548	610-	17-		0	610	17
2008	3,831-	1,635-	43		0	1,635	43-
2009	4,100	295,044-			0	295,044	
TOTAL	2,811,705	297,829-	11-		0	297,829	11

THREE-YEAR MOVING AVERAGES

03-05	935,478	436-	0		0	436	0
04-06	971	190-	20-		0	190	20
05-07	2,134	358-	17-		0	358	17
06-08	391	492-	126-		0	492	126
07-09	1,273	99,096-			0	99,096	

FIVE-YEAR AVERAGE

05-09	1,334	59,551-			0	59,551	

FORTISBC, INC.

ACCOUNT 373.00 - STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995		157				157-	
1996							
1997							
1998							
1999	1,622	27	2		0	27-	2-
2000	417,141	113	0		0	113-	0
2001							
2002							
2003	8,100		0		0		0
2004	26,253	660	3		0	660-	3-
2005	23,390	2	0		0	2-	0
2006	49,475		0		0		0
2007	52,676	1-	0		0	1	0
2008	46,051	1	0		0	1-	0
2009	52,739	124,577	236		0	124,577-	236-
TOTAL	677,445	125,536	19		0	125,536-	19-
THREE-YEAR MOVING AVERAGES							
95-97		52				52-	
96-98							
97-99	541	9	2		0	9-	2-
98-00	139,588	47	0		0	47-	0
99-01	139,588	47	0		0	47-	0
00-02	139,047	38	0		0	38-	0
01-03	2,700		0		0		0
02-04	11,451	220	2		0	220-	2-
03-05	19,247	221	1		0	221-	1-
04-06	33,039	220	1		0	220-	1-
05-07	41,847		0		0		0
06-08	49,400		0		0		0
07-09	50,488	41,525	82		0	41,525-	82-
FIVE-YEAR AVERAGE							
05-09	44,866	24,916	56		0	24,916-	56-

FORTISBC, INC.

ACCOUNT 390.10 - STRUCTURES - MASONRY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2002	132,286	127-	0		0	127	0
2003	572,749	6	0		0	6-	0
2004	20,325	204	1		0	204-	1-
2005	18,600	4	0		0	4-	0
2006	11,835	489	4		0	489-	4-
2007		2,547				2,547-	
2008		723				723-	
2009		525				525-	
TOTAL	755,795	4,371	1		0	4,371-	1-
THREE-YEAR MOVING AVERAGES							
02-04	241,787	27	0		0	27-	0
03-05	203,891	71	0		0	71-	0
04-06	16,920	232	1		0	232-	1-
05-07	10,145	1,013	10		0	1,013-	10-
06-08	3,945	1,253	32		0	1,253-	32-
07-09		1,265				1,265-	
FIVE-YEAR AVERAGE							
05-09	6,087	858	14		0	858-	14-

FORTISBC, INC.

ACCOUNT 397.00 - COMMUNICATIONS STRUCTURES AND EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	60,914-		0		0		0
1996	99,252		0		0		0
1997	58,157-		0		0		0
1998	1,052,266		0		0		0
1999	765,028-	73	0		0	73-	0
2000	673,866-	14	0		0	14-	0
2001							
2002							
2003							
2004							
2005							
2006	129,725	53	0		0	53-	0
2007		74				74-	
2008		461				461-	
2009	54,750	16,118	29		0	16,118-	29-
TOTAL	221,970-	16,793	8-		0	16,793-	8
THREE-YEAR MOVING AVERAGES							
95-97	6,606-		0		0		0
96-98	364,454		0		0		0
97-99	76,360	24	0		0	24-	0
98-00	128,876-	29	0		0	29-	0
99-01	479,631-	29	0		0	29-	0
00-02	224,622-	5	0		0	5-	0
01-03							
02-04							
03-05							
04-06	43,242	17	0		0	17-	0
05-07	43,242	42	0		0	42-	0
06-08	43,242	196	0		0	196-	0
07-09	18,250	5,551	30		0	5,551-	30-
FIVE-YEAR AVERAGE							
05-09	36,895	3,341	9		0	3,341-	9-

PART VI. DETAILED DEPRECIATION CALCULATIONS

FORTISBC, INC.

ACCOUNT 330.10 - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1940	15,997.99	13,042	26,839-	42,837	13.86	3,091
1982	82,941.01	30,080	61,902-	144,843	47.80	3,030
1983	862,419.15	301,614	620,698-	1,483,117	48.77	30,410
	961,358.15	344,736	709,439-	1,670,797		36,531

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 45.7 3.80

FORTISBC, INC.

ACCOUNT 331.00 - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-L3						
NET SALVAGE PERCENT.. -15						
1940	298,669.34	249,988	343,470			
1982	763,756.14	385,433	566,746	311,574	33.67	9,254
1984	3,635.15	1,714	2,520	1,660	35.40	47
1985	49,239.74	22,377	32,903	23,723	36.29	654
1986	53,338.48	23,329	34,303	27,036	37.18	727
1990	762,553.66	280,032	411,763	465,174	40.84	11,390
1993	1,136,310.02	355,438	522,641	784,116	43.68	17,951
1994	173,635.56	51,152	75,215	124,466	44.63	2,789
1995	2,188,403.51	603,999	888,129	1,628,535	45.60	35,713
1996	147,395.52	37,940	55,788	113,717	46.57	2,442
1997	94,201.20	22,479	33,053	75,278	47.55	1,583
1998	2,970,614.06	653,076	960,293	2,455,913	48.53	50,606
1999	84,961.99	17,066	25,094	72,612	49.52	1,466
2000	1,169,574.11	212,740	312,816	1,032,194	50.51	20,435
2001	982,999.38	160,151	235,488	894,961	51.50	17,378
2002	385,145.41	55,365	81,409	361,508	52.50	6,886
2003	576,182.13	71,780	105,547	557,062	53.50	10,412
2004	174,693.70	18,416	27,079	173,819	54.50	3,189
2006	1.00	0	0	1		
	12,015,310.10	3,222,475	4,714,257	9,103,350		192,922

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 47.2   1.61

FORTISBC, INC.

ACCOUNT 332.00 - RESERVOIRS, DAMS, AND WATERWAYS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. -15						
1940	857,944.73	838,927	293,219	693,417	10.48	66,166
1960	84,404.59	64,410	22,512	74,553	23.55	3,166
1977	3,738.80	1,957	684	3,616	38.14	95
1982	14,166,722.36	6,316,467	2,207,714	14,084,017	42.86	328,605
1984	8,296.59	3,438	1,202	8,339	44.78	186
1986	21,374.06	8,178	2,858	21,722	46.71	465
1987	246,209.31	90,282	31,555	251,586	47.68	5,277
1988	235,387.67	82,524	28,844	241,852	48.66	4,970
1989	325,880.80	109,004	38,099	336,664	49.64	6,782
1990	157,574.30	50,170	17,535	163,675	50.62	3,233
1991	957,262.28	289,370	101,140	999,712	51.60	19,374
1992	472,331.33	135,095	47,218	495,963	52.59	9,431
1993	2,984,148.79	805,471	281,526	3,150,245	53.57	58,806
1994	1,235,862.59	313,483	109,568	1,311,674	54.56	24,041
1996	13,077.52	2,892	1,011	14,028	56.54	248
1997	21,677.48	4,437	1,551	23,378	57.54	406
2000	699,749.87	108,982	38,091	766,621	60.52	12,667
2003	847,544.28	90,362	31,583	943,093	63.51	14,850
2004	1,104,239.69	99,596	34,810	1,235,066	64.51	19,145
	24,443,427.04	9,415,045	3,290,720	24,819,221		577,913

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 42.9   2.36

FORTISBC, INC.

ACCOUNT 333.00 - WATER WHEELS, TURBINES, AND GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. -50						
1940	893,140.36	1,019,788	157,305	1,182,406	17.91	66,019
1960	15,302,210.91	13,499,534	2,082,335	20,870,981	30.89	675,655
1979	1,623.26	931	144	2,291	46.31	49
1982	14,904,729.96	7,765,290	1,197,814	21,159,281	48.95	432,263
1984	53,718.78	26,065	4,021	76,557	50.74	1,509
1985	17,101.05	7,986	1,232	24,420	51.65	473
1986	43,664.51	19,597	3,023	62,474	52.56	1,189
1987	8,681.26	3,738	577	12,445	53.47	233
1990	46,504.95	17,448	2,691	67,066	56.24	1,192
1993	53,178.73	16,964	2,617	77,151	59.05	1,307
1994	143,570.42	43,099	6,648	208,708	59.99	3,479
1995	257,957.45	72,539	11,189	375,747	60.94	6,166
1996	433,197.92	113,584	17,521	632,276	61.89	10,216
1997	172,351.74	41,915	6,465	252,063	62.84	4,011
1998	4,775,108.54	1,069,600	164,988	6,997,675	63.80	109,681
1999	124,936.62	25,586	3,947	183,458	64.76	2,833
2000	3,292,692.10	610,465	94,166	4,844,872	65.73	73,709
2001	6,783,118.10	1,127,354	173,897	10,000,780	66.69	149,959
2002	167,160.90	24,540	3,785	246,956	67.66	3,650
2003	111,187.29	14,165	2,185	164,596	68.63	2,398
2004	13,796,570.11	1,487,339	229,425	20,465,430	69.61	294,001
	61,382,404.96	27,007,527	4,165,975	87,907,632		1,839,992

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 47.8 3.00

FORTISBC, INC.

ACCOUNT 334.00 - ACCESSORY ELECTRICAL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -30						
1950	493,651.95	559,219	394,020	247,728	6.43	38,527
1960	4,547,525.89	4,691,592	3,305,650	2,606,134	10.32	252,532
1975	6,235.54	4,946	3,485	4,621	19.49	237
1976	9,782.54	7,574	5,337	7,380	20.22	365
1977	4,381.24	3,307	2,330	3,366	20.97	161
1978	12,182.69	8,958	6,312	9,525	21.72	439
1982	859,690.07	562,151	396,086	721,511	24.85	29,035
1984	79,888.05	48,853	34,421	69,433	26.48	2,622
1986	150,727.11	85,628	60,333	135,612	28.15	4,817
1993	213,283.18	87,173	61,421	215,847	34.28	6,297
1994	102,985.32	39,656	27,941	105,940	35.19	3,011
1995	409,096.00	147,741	104,097	427,728	36.11	11,845
1996	470,383.76	158,623	111,764	499,735	37.03	13,495
1997	5,108,706.16	1,599,229	1,126,801	5,514,517	37.96	145,272
1998	555,990.89	160,604	113,160	609,628	38.89	15,676
1999	207,158.75	54,723	38,557	230,749	39.84	5,792
2000	4,393,692.76	1,053,256	742,114	4,969,687	40.78	121,866
2001	3,403,629.72	730,964	515,031	3,909,688	41.74	93,668
2002	1,009,074.92	191,785	135,130	1,176,667	42.69	27,563
2003	196,317.30	32,361	22,801	232,411	43.66	5,323
2004	5,259,082.96	735,641	518,326	6,318,482	44.62	141,606
	27,493,466.80	10,963,984	7,725,117	28,016,390		920,149

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 30.4 3.35

FORTISBC, INC.

ACCOUNT 335.00 - OTHER POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 45-R4
NET SALVAGE PERCENT.. -5

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1960	28,598.82	26,819	22,838	7,191	4.81	1,495
1982	5,097,116.40	3,135,078	2,669,749	2,682,223	18.64	143,896
1984	62,215.73	35,770	30,461	34,866	20.36	1,712
1985	103,415.43	57,334	48,824	59,762	21.24	2,814
1986	486,237.40	259,359	220,863	289,686	22.14	13,084
1987	58,639.16	30,047	25,587	35,984	23.04	1,562
1989	110,671.56	51,931	44,223	71,982	24.89	2,892
1990	291,172.03	130,309	110,968	194,763	25.82	7,543
1991	103,328.50	43,952	37,428	71,067	26.77	2,655
1992	278,293.24	112,208	95,553	196,655	27.72	7,094
1993	379,591.18	144,550	123,095	275,476	28.68	9,605
1994	308,914.78	110,643	94,221	230,140	29.65	7,762
1995	79,286.41	26,604	22,655	60,596	30.62	1,979
1996	382,697.82	119,746	101,972	299,861	31.59	9,492
1997	351,364.26	101,825	86,711	282,221	32.58	8,662
1998	1,279,263.40	341,475	290,791	1,052,436	33.56	31,360
1999	708,205.87	172,683	147,052	596,564	34.55	17,267
2000	937,835.73	207,009	176,283	808,445	35.54	22,747
2001	710,087.00	140,335	119,506	626,085	36.53	17,139
2002	495,110.01	86,412	73,586	446,280	37.52	11,894
2003	18,238,607.57	2,761,891	2,351,953	16,798,585	38.51	436,214
2004	10,403,338.19	1,332,668	1,134,865	9,788,640	39.51	247,751
	40,893,990.49	9,428,648	8,029,184	34,909,506		1,006,619

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 34.7   2.46

FORTISBC, INC.

ACCOUNT 336.00 - ROADS, RAILROADS AND BRIDGES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-S4						
NET SALVAGE PERCENT.. 0						
1950	2,711.76	2,044	1,418	1,294	18.46	70
1982	672,532.49	246,597	171,028	501,504	47.50	10,558
1984	17,837.70	6,065	4,206	13,632	49.50	275
1999	534,057.85	74,768	51,856	482,202	64.50	7,476
2000	31,457.91	3,985	2,764	28,694	65.50	438
2001	1,398.00	158	110	1,288	66.50	19
2002	12,086.49	1,209	838	11,248	67.50	167
2003	14,433.54	1,251	868	13,566	68.50	198
2004	919.03	67	46	873	69.50	13
	1,287,434.77	336,144	233,134	1,054,301		19,214

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 54.9 1.49

FORTISBC, INC.

ACCOUNT 350.10 - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1940	901,044.23	685,875	578,770	322,274	17.91	17,994
1957	88,454.10	54,605	46,078	42,376	28.70	1,477
1958	1,723.12	1,047	884	839	29.42	29
1961	9,227.20	5,335	4,502	4,725	31.64	149
1962	12,889.30	7,323	6,179	6,710	32.39	207
1963	15,046.65	8,396	7,085	7,962	33.15	240
1976	6,737.64	2,810	2,371	4,367	43.72	100
1977	7,836.21	3,179	2,683	5,153	44.57	116
1978	6,522.00	2,571	2,170	4,352	45.44	96
1979	3,535.15	1,352	1,141	2,394	46.31	52
1980	6,469.42	2,400	2,025	4,444	47.18	94
1981	48,516.60	17,421	14,701	33,816	48.07	703
1982	6,595.29	2,291	1,933	4,662	48.95	95
1983	440.75	148	125	316	49.85	6
1984	83,304.12	26,946	22,738	60,566	50.74	1,194
1985	41,323.87	12,865	10,856	30,468	51.65	590
1986	205,509.88	61,489	51,887	153,623	52.56	2,923
1987	5,529.07	1,587	1,339	4,190	53.47	78
1988	174.61	48	41	134	54.39	2
1989	17,453.89	4,582	3,866	13,588	55.31	246
1990	16,027.30	4,009	3,383	12,644	56.24	225
1991	2,011.69	478	403	1,609	57.17	28
1992	512,566.64	115,430	97,405	415,162	58.11	7,144
1996	19,552.08	3,418	2,884	16,668	61.89	269
1997	57,754.66	9,364	7,902	49,853	62.84	793
1998	273,697.23	40,871	34,489	239,208	63.80	3,749
2000	391,598.57	48,402	40,843	350,756	65.73	5,336
2001	23,665.44	2,622	2,213	21,452	66.69	322
2002	48,268.24	4,724	3,986	44,282	67.66	654
2003	729,921.45	61,992	52,311	677,610	68.63	9,873
2004	1,355,117.11	97,392	82,184	1,272,933	69.61	18,287
2008	798,952.60	15,763	13,301	785,652	73.52	10,686
2009	101,053.58	660	557	100,497	74.51	1,349
	5,798,519.69	1,307,395	1,103,235	4,695,285		85,106

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 55.2 1.47

FORTISBC, INC.

ACCOUNT 353.00 - SUBSTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S4						
NET SALVAGE PERCENT.. -30						
1950	8,203,136.45	9,759,764	4,317,506	6,346,571	4.24	1,496,833
1960	3,549,228.16	3,951,427	1,748,025	2,865,972	7.18	399,160
1966	4,318,698.21	4,494,815	1,988,408	3,625,900	9.97	363,681
1973	6,592,949.01	6,068,150	2,684,417	5,886,417	14.60	403,179
1975	2,212,221.52	1,943,525	859,773	2,016,115	16.21	124,375
1976	333,854.77	285,927	126,488	307,523	17.06	18,026
1977	916,285.13	764,017	337,984	853,187	17.93	47,584
1978	8,689,173.28	7,044,139	3,116,173	8,179,752	18.82	434,631
1980	5,162,685.13	3,936,960	1,741,625	4,969,866	20.67	240,439
1982	3,279,039.15	2,337,693	1,034,144	3,228,607	22.58	142,985
1984	284,838.93	188,552	83,411	286,880	24.54	11,690
1985	4,365,459.60	2,778,528	1,229,160	4,445,937	25.52	174,214
1986	3,307,784.57	2,020,196	893,690	3,406,430	26.51	128,496
1988	927,410.58	518,423	229,339	976,295	28.50	34,256
1989	2,133,151.05	1,136,970	502,971	2,270,125	29.50	76,953
1990	208,615.23	105,768	46,789	224,411	30.50	7,358
1992	440,480.31	200,419	88,661	483,963	32.50	14,891
1993	1,834,587.26	787,038	348,168	2,036,795	33.50	60,800
1994	22,683,546.22	9,141,469	4,043,986	25,444,624	34.50	737,525
1995	1,887,840.82	711,716	314,848	2,139,345	35.50	60,263
1996	4,109,560.99	1,442,456	638,111	4,704,318	36.50	128,885
1998	2,716,697.46	812,293	359,341	3,172,366	38.50	82,399
1999	655,393.83	178,923	79,152	772,860	39.50	19,566
2000	1,119,856.46	276,605	122,364	1,333,449	40.50	32,925
2001	2,879,134.00	636,289	281,480	3,461,394	41.50	83,407
2002	38,782.97	7,563	3,346	47,072	42.50	1,108
2003	10,450,079.42	1,766,063	781,267	12,803,836	43.50	294,341
2004	6,326,885.21	904,745	400,239	7,824,712	44.50	175,836
2005	19,410,270.27	2,271,002	1,004,641	24,228,710	45.50	532,499
2006	9,198,610.72	837,074	370,303	11,587,891	46.50	249,202
	138,236,256.71	67,308,509	29,775,810	149,931,324		6,577,507

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 22.8   4.76

FORTISBC, INC.

ACCOUNT 355.00 - POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -50						
1950	632,198.52	826,347	421,839	526,459	6.43	81,875
1957	6,345,812.44	7,811,061	3,987,443	5,531,276	8.97	616,642
1958	146,591.03	178,548	91,146	128,741	9.40	13,696
1959	5,970.45	7,191	3,671	5,285	9.85	537
1961	250,931.41	295,020	150,604	225,793	10.81	20,887
1962	443,051.96	514,117	262,450	402,128	11.32	35,524
1963	61,725.69	70,645	36,063	56,526	11.85	4,770
1964	357,972.37	403,900	206,186	330,773	12.39	26,697
1965	3,099,262.64	3,443,901	1,758,066	2,890,828	12.96	223,058
1975	176,448.95	161,504	82,446	182,227	19.49	9,350
1976	1,126,169.76	1,006,120	513,611	1,175,644	20.22	58,143
1977	551,913.86	480,662	245,372	582,499	20.97	27,778
1978	60,308.09	51,165	26,119	64,343	21.72	2,962
1979	215,686.87	178,006	90,870	232,660	22.49	10,345
1980	752,262.50	603,465	308,061	820,333	23.26	35,268
1981	315,943.26	245,962	125,560	348,355	24.05	14,485
1982	618,789.79	466,877	238,334	689,851	24.85	27,761
1983	824,207.49	601,836	307,229	929,082	25.66	36,207
1984	1,625,614.62	1,147,034	585,546	1,852,876	26.48	69,973
1985	2,562,889.55	1,744,559	890,574	2,953,760	27.31	108,157
1986	713,798.72	467,895	238,854	831,844	28.15	29,550
1987	1,464,747.28	922,791	471,072	1,726,049	29.00	59,519
1988	252,902.00	152,803	78,004	301,349	29.86	10,092
1989	636,070.79	367,713	187,713	766,393	30.73	24,940
1990	752,583.06	415,426	212,069	916,806	31.60	29,013
1991	885,688.37	465,252	237,505	1,091,028	32.49	33,580
1992	597,460.56	297,894	152,071	744,120	33.38	22,292
1993	866,444.93	408,615	208,592	1,091,075	34.28	31,828
1994	3,896,772.62	1,731,336	883,824	4,961,335	35.19	140,987
1995	487,997.81	203,349	103,807	628,190	36.11	17,397
1996	4,412,486.84	1,716,899	876,454	5,742,276	37.03	155,071
1997	1,590,457.89	574,473	293,261	2,092,426	37.96	55,122
1998	3,119,903.36	1,039,864	530,837	4,149,018	38.89	106,686
1999	816,718.46	248,936	127,078	1,098,000	39.84	27,560
2000	2,651,753.37	733,475	374,429	3,603,201	40.78	88,357
2001	1,207,209.50	299,147	152,711	1,658,103	41.74	39,725
2002	921,246.30	202,029	103,133	1,278,736	42.69	29,954
2003	8,733,298.36	1,661,073	847,955	12,251,993	43.66	280,623
2004	7,347,474.81	1,185,882	605,377	10,415,835	44.62	233,434
2005	1,978,358.44	261,737	133,613	2,833,925	45.59	62,161
2007	8,335,410.26	615,153	314,028	12,189,087	47.54	256,396
2009	869,674.90	12,784	6,526	1,297,986	49.51	26,217
	72,712,209.88	34,222,446	17,470,103	91,598,212		3,184,619

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 28.8 4.38

FORTISBC, INC.

ACCOUNT 356.00 - CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -50						
1950	1,447,408.55	1,724,580	845,969	1,325,144	12.34	107,386
1957	5,823,386.78	6,395,564	3,137,257	5,597,823	16.07	348,340
1958	116,054.92	125,745	61,682	112,400	16.66	6,747
1959	21,968.60	23,468	11,512	21,441	17.27	1,242
1961	662,266.88	686,608	336,806	656,594	18.53	35,434
1962	441,754.31	450,808	221,138	441,493	19.18	23,018
1963	61,725.24	61,972	30,400	62,188	19.84	3,134
1965	3,094,636.30	3,002,555	1,472,862	3,169,092	21.19	149,556
1975	195,443.41	153,276	75,187	217,978	28.63	7,614
1976	897,338.27	686,020	336,518	1,009,489	29.42	34,313
1977	570,854.88	424,862	208,410	647,872	30.23	21,431
1978	77,751.02	56,292	27,613	89,014	31.04	2,868
1979	343,281.46	241,499	118,464	396,458	31.86	12,444
1980	541,261.30	369,549	181,277	630,615	32.69	19,291
1981	227,020.16	150,232	73,694	266,836	33.53	7,958
1982	651,233.22	417,115	204,610	772,240	34.38	22,462
1983	451,534.70	279,611	137,159	540,143	35.23	15,332
1984	1,649,310.96	985,876	483,608	1,990,358	36.09	55,150
1985	2,007,159.74	1,156,124	567,121	2,443,619	36.96	66,115
1986	674,946.60	373,917	183,420	829,000	37.84	21,908
1987	763,300.21	406,080	199,197	945,753	38.72	24,425
1988	1,466,806.22	747,697	366,773	1,833,436	39.61	46,287
1989	701,767.35	341,933	167,731	884,920	40.51	21,844
1990	882,002.13	409,906	201,074	1,121,929	41.41	27,093
1991	836,475.65	369,726	181,364	1,073,349	42.32	25,363
1992	700,334.08	293,436	143,941	906,560	43.24	20,966
1993	822,358.90	325,654	159,745	1,073,793	44.16	24,316
1994	4,209,430.04	1,570,138	770,210	5,543,935	45.08	122,980
1995	336,465.29	117,595	57,685	447,013	46.02	9,713
1996	4,669,323.99	1,522,176	746,683	6,257,303	46.96	133,248
1997	1,618,922.79	489,732	240,231	2,188,153	47.90	45,682
1998	3,330,760.07	928,433	455,430	4,540,710	48.85	92,952
2000	2,729,484.54	631,207	309,630	3,784,597	50.75	74,573
2001	2,378,878.74	493,035	241,852	3,326,466	51.71	64,329
2002	909,775.71	166,489	81,669	1,282,995	52.68	24,354
2003	7,688,957.81	1,222,544	599,702	10,933,735	53.64	203,835
2004	6,660,662.69	895,892	439,467	9,551,527	54.62	174,872
2005	543,851.95	59,960	29,413	786,365	55.59	14,146
2007	8,335,721.98	512,647	251,472	12,252,111	57.54	212,932
2009	905,834.78	11,101	5,445	1,353,307	59.51	22,741
	70,447,452.22	29,281,054	14,363,421	91,307,757		2,348,394

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 38.9 3.33

FORTISBC, INC.

ACCOUNT 359.00 - ROADS AND TRAILS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R0.5						
NET SALVAGE PERCENT.. 0						
1975	4,415.60	2,208	1,071	3,345	20.00	167
1976	13,486.84	6,571	3,187	10,300	20.51	502
1977	2,578.63	1,223	593	1,986	21.03	94
1978	640.35	295	143	497	21.56	23
1979	2,376.35	1,064	516	1,860	22.09	84
1980	26,294.36	11,425	5,542	20,752	22.62	917
1982	57,486.72	23,411	11,355	46,132	23.71	1,946
2003	309,623.31	30,962	15,018	294,605	36.00	8,183
2004	400,777.56	33,966	16,475	384,303	36.61	10,497
2009	304,250.00	2,358	1,144	303,106	39.69	7,637
	1,121,929.72	113,483	55,044	1,066,886		30,050

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 35.5   2.68

FORTISBC, INC.

ACCOUNT 360.10 - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1960	6,137,906.93	3,609,887	412,909	5,724,998	30.89	185,335
1975	33,928.61	14,539	1,663	32,266	42.86	753
1976	111,679.90	46,578	5,328	106,352	43.72	2,433
1977	28,932.60	11,739	1,343	27,590	44.57	619
1978	77,816.84	30,670	3,508	74,309	45.44	1,635
1979	94,286.61	36,067	4,125	90,162	46.31	1,947
1980	120,995.42	44,881	5,134	115,861	47.18	2,456
1981	69,523.20	24,964	2,855	66,668	48.07	1,387
1982	87,180.85	30,281	3,464	83,717	48.95	1,710
1983	171,554.97	57,528	6,580	164,975	49.85	3,309
1984	25,822.03	8,353	955	24,867	50.74	490
1985	129,629.49	40,358	4,616	125,013	51.65	2,420
1986	108,729.76	32,532	3,721	105,009	52.56	1,998
1987	48,528.00	13,931	1,594	46,934	53.47	878
1988	23,912.68	6,571	752	23,161	54.39	426
1989	263.49	69	8	255	55.31	5
1990	36,865.70	9,221	1,055	35,811	56.24	637
1991	99,480.88	23,650	2,705	96,776	57.17	1,693
1998	129,992.26	19,412	2,220	127,772	63.80	2,003
1999	187,876.08	25,651	2,934	184,942	64.76	2,856
2000	81,105.31	10,025	1,147	79,958	65.73	1,216
2001	18,132.00	2,009	230	17,902	66.69	268
2004	2.00	0	0	2		
2006	652,955.00	29,951	3,425	649,530	71.56	9,077
	8,477,100.61	4,128,867	472,271	8,004,830		225,551

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 35.5   2.66

FORTISBC, INC.

ACCOUNT 362.00 - SUBSTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S3						
NET SALVAGE PERCENT.. -20						
1960	2,021,091.22	1,843,672	1,037,930	1,387,379	13.19	105,184
1961	564,667.59	509,312	286,727	390,874	13.66	28,614
1962	100,760.88	89,806	50,558	70,355	14.15	4,972
1966	5,109,370.15	4,314,189	2,428,754	3,702,490	16.30	227,147
1968	3,237,033.69	2,649,888	1,491,804	2,392,636	17.48	136,878
1969	7,180,709.11	5,779,580	3,253,724	5,363,127	18.11	296,142
1970	956,634.91	756,610	425,948	722,014	18.75	38,507
1971	209,758.39	162,879	91,696	160,014	19.41	8,244
1972	896,167.27	682,396	384,168	691,233	20.10	34,390
1973	463,424.62	345,700	194,618	361,492	20.81	17,371
1974	290,150.38	211,885	119,285	228,895	21.53	10,631
1975	2,020,783.16	1,442,621	812,151	1,612,789	22.28	72,387
1976	1,262,486.06	880,069	495,451	1,019,532	23.05	44,231
1977	2,504,469.02	1,702,688	958,560	2,046,803	23.84	85,856
1978	8,745,014.17	5,790,808	3,260,045	7,233,972	24.65	293,467
1979	1,167,884.38	752,206	423,469	977,992	25.48	38,383
1980	4,379,670.53	2,739,589	1,542,303	3,713,302	26.33	141,029
1981	1,252,078.95	759,721	427,699	1,074,796	27.19	39,529
1982	1,799,715.59	1,057,455	595,314	1,564,345	28.07	55,730
1983	3,584,638.10	2,035,802	1,146,093	3,155,473	28.97	108,922
1984	4,267,545.92	2,338,939	1,316,750	3,804,305	29.88	127,319
1985	310,679.51	164,039	92,349	280,466	30.80	9,106
1986	558,860.65	283,617	159,668	510,965	31.74	16,098
1987	5,384,271.66	2,622,054	1,476,135	4,984,991	32.68	152,540
1988	1,230,061.44	573,248	322,721	1,153,353	33.64	34,285
1989	559,975.74	249,120	140,247	531,724	34.61	15,363
1990	2,578,877.30	1,092,691	615,151	2,479,502	35.58	69,688
1991	7,091,885.28	2,853,236	1,606,283	6,903,979	36.56	188,840
1992	844,221.31	321,598	181,050	832,016	37.54	22,163
1993	1,567,592.49	563,299	317,120	1,563,991	38.53	40,592
1994	3,266,494.96	1,103,226	621,082	3,298,712	39.52	83,469
1995	3,893,920.44	1,231,024	693,028	3,979,677	40.51	98,239
1996	3,093,525.89	910,499	512,583	3,199,648	41.51	77,081
1997	2,431,466.25	663,119	373,315	2,544,444	42.50	59,869
1998	342,635.30	85,970	48,398	362,764	43.50	8,339
1999	3,047,637.55	698,189	393,059	3,264,106	44.50	73,351
2000	3,208,016.19	664,945	374,343	3,475,276	45.50	76,380
2001	1,663,158.87	308,449	173,647	1,822,144	46.50	39,186
2002	835,465.09	136,709	76,963	925,595	47.50	19,486
2003	28,052,019.53	3,978,225	2,239,617	31,422,806	48.50	647,893
2004	1,573,115.97	188,774	106,274	1,781,465	49.50	35,989

FORTISBC, INC.

ACCOUNT 362.00 - SUBSTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S3						
NET SALVAGE PERCENT.. -20						
2006	296,208.00	22,621	12,735	342,715	51.50	6,655
2007	10,549,287.92	575,358	323,908	12,335,238	52.50	234,957
2008	29,162,417.31	954,311	537,247	34,457,654	53.50	644,068
2009	17,674,813.42	192,797	108,539	21,101,237	54.50	387,179
	181,230,662.16	57,282,933	32,248,509	185,228,286		4,955,749

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 37.4 2.73

FORTISBC, INC.

ACCOUNT 364.00 - POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -40						
1960	11,645,887.24	12,939,047	9,414,870	6,889,372	10.32	667,575
1975	646,987.85	552,709	402,169	503,614	19.49	25,840
1976	890,158.39	742,250	540,085	706,137	20.22	34,923
1977	1,018,489.39	827,869	602,384	823,501	20.97	39,270
1978	1,058,976.27	838,540	610,149	872,418	21.72	40,167
1979	1,184,208.27	912,172	663,726	994,166	22.49	44,205
1980	1,405,233.93	1,052,127	765,562	1,201,766	23.26	51,667
1981	1,974,494.38	1,434,668	1,043,911	1,720,381	24.05	71,534
1982	938,300.03	660,751	480,784	832,836	24.85	33,515
1983	1,002,875.21	683,480	497,322	906,703	25.66	35,335
1984	934,361.96	615,333	447,736	860,371	26.48	32,491
1985	1,308,163.32	831,102	604,737	1,226,692	27.31	44,917
1986	1,375,902.49	841,777	612,504	1,313,759	28.15	46,670
1987	730,072.78	429,283	312,360	709,742	29.00	24,474
1988	1,293,436.00	729,394	530,731	1,280,079	29.86	42,869
1989	1,427,302.41	770,115	560,361	1,437,862	30.73	46,790
1990	1,222,541.78	629,854	458,302	1,253,256	31.60	39,660
1991	1,533,719.27	751,952	547,145	1,600,062	32.49	49,248
1992	9,778,049.03	4,550,313	3,310,955	10,378,314	33.38	310,914
1993	2,761,673.57	1,215,578	884,494	2,981,849	34.28	86,985
1994	4,327,917.51	1,794,701	1,305,883	4,753,202	35.19	135,073
1995	4,956,378.54	1,927,635	1,402,610	5,536,320	36.11	153,318
1996	3,280,555.63	1,191,367	866,877	3,725,901	37.03	100,618
1997	4,141,671.04	1,396,240	1,015,950	4,782,389	37.96	125,985
1998	3,715,973.81	1,155,965	841,118	4,361,245	38.89	112,143
1999	3,857,187.17	1,097,293	798,426	4,601,636	39.84	115,503
2000	3,948,376.86	1,019,313	741,685	4,786,043	40.78	117,363
2001	4,616,180.04	1,067,630	776,842	5,685,810	41.74	136,220
2004	5,406,022.29	814,363	592,557	6,975,874	44.62	156,340
2005	7,690,623.65	949,638	690,987	10,075,886	45.59	221,011
2006	15,623,229.38	1,500,455	1,091,780	20,780,741	46.57	446,226
2007	9,502,824.92	654,555	476,275	12,827,680	47.54	269,829
2008	11,780,670.01	488,191	355,224	16,137,714	48.52	332,599
	126,978,444.42	47,065,660	34,246,501	143,523,321		4,191,277

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 34.2   3.30

FORTISBC, INC.

ACCOUNT 365.00 - CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -25

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1960	14,985,969.77	15,743,511	10,849,269	7,883,193	7.18	1,097,938
1975	567,922.97	471,220	324,730	385,174	15.13	25,458
1976	750,314.64	608,383	419,253	518,640	15.81	32,805
1977	1,023,977.70	810,363	558,443	721,529	16.51	43,703
1978	1,159,924.53	895,070	616,816	833,090	17.22	48,379
1979	1,753,461.59	1,318,011	908,276	1,283,551	17.94	71,547
1980	2,260,066.04	1,652,363	1,138,687	1,686,396	18.68	90,278
1981	2,790,629.88	1,981,347	1,365,398	2,122,889	19.44	109,202
1982	2,776,557.77	1,912,736	1,318,117	2,152,580	20.20	106,563
1983	1,598,791.69	1,066,754	735,128	1,263,362	20.98	60,217
1984	1,991,458.69	1,285,039	885,554	1,603,769	21.77	73,669
1985	1,980,796.47	1,234,135	850,475	1,625,521	22.57	72,021
1986	2,327,962.72	1,398,058	963,439	1,946,514	23.38	83,256
1987	2,030,873.81	1,172,830	808,228	1,730,364	24.21	71,473
1988	2,197,422.00	1,218,361	839,605	1,907,172	25.04	76,165
1989	2,600,564.10	1,380,477	951,323	2,299,382	25.89	88,814
1990	4,575,834.09	2,320,977	1,599,446	4,120,347	26.74	154,089
1991	4,415,416.72	2,132,867	1,469,815	4,049,456	27.61	146,666
1992	9,917,867.80	4,548,458	3,134,462	9,262,873	28.49	325,127
1993	6,258,899.15	2,717,379	1,872,618	5,951,006	29.37	202,622
1994	8,767,093.14	3,587,166	2,472,011	8,486,855	30.27	280,372
1995	5,113,646.29	1,964,471	1,353,769	5,038,289	31.17	161,639
1996	5,444,537.11	1,953,976	1,346,536	5,459,135	32.08	170,173
1997	9,476,339.05	3,158,819	2,176,825	9,668,599	33.00	292,988
1998	5,246,091.44	1,613,173	1,111,680	5,445,934	33.93	160,505
1999	4,984,264.50	1,403,880	967,451	5,262,880	34.86	150,972
2000	5,247,651.01	1,339,594	923,150	5,636,414	35.81	157,398
2001	7,554,840.35	1,731,286	1,193,075	8,250,475	36.75	224,503
2002	4,922,746.16	996,856	686,960	5,466,473	37.71	144,961
2003	9,068,790.58	1,594,633	1,098,904	10,237,084	38.67	264,729
2004	7,968,589.07	1,188,615	819,106	9,141,630	39.63	230,674
2005	11,089,298.70	1,355,390	934,035	12,927,588	40.60	318,413
2006	21,584,038.33	2,056,419	1,417,132	25,562,916	41.57	614,937
2007	16,534,700.14	1,125,186	775,395	19,892,980	42.55	467,520
2008	18,019,342.48	735,865	507,104	22,017,074	43.53	505,791
	208,986,680.48	71,673,668	49,392,215	211,841,136		7,125,567

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 29.7 3.41

FORTISBC, INC.

ACCOUNT 368.00 - LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 45-R4
NET SALVAGE PERCENT.. -25

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1960	9,419,353.20	10,515,648	5,020,827	6,753,364	4.81	1,404,026
1975	559,304.79	495,139	236,410	462,721	13.13	35,242
1976	814,416.07	704,470	336,358	681,662	13.86	49,182
1977	840,901.54	709,626	338,820	712,307	14.62	48,721
1978	1,102,007.88	906,401	432,772	944,738	15.39	61,386
1979	927,567.35	742,564	354,546	804,913	16.18	49,747
1980	1,057,028.61	822,725	392,820	928,466	16.98	54,680
1981	1,611,974.89	1,217,484	581,303	1,433,666	17.81	80,498
1982	772,040.35	565,307	269,913	695,137	18.64	37,293
1983	573,198.06	406,175	193,933	522,565	19.49	26,812
1984	395,528.93	270,720	129,259	365,152	20.36	17,935
1985	728,146.98	480,577	229,458	680,726	21.24	32,049
1986	493,234.82	313,204	149,543	467,001	22.14	21,093
1987	332,855.14	203,042	96,945	319,124	23.04	13,851
1988	402,383.22	235,173	112,286	390,693	23.96	16,306
1989	497,600.57	277,966	132,718	489,283	24.89	19,658
1990	342,639.46	182,550	87,161	341,138	25.82	13,212
1991	348,071.21	176,259	84,157	350,932	26.77	13,109
1992	6,879,629.06	3,302,222	1,576,687	7,022,849	27.72	253,350
1993	1,323,051.96	599,789	286,377	1,367,438	28.68	47,679
1994	1,880,004.11	801,610	382,739	1,967,266	29.65	66,350
1995	1,137,341.23	454,311	216,916	1,204,761	30.62	39,346
1996	1,015,636.35	378,325	180,636	1,088,909	31.59	34,470
1997	1,048,625.88	361,776	172,735	1,138,047	32.58	34,931
1998	1,296,983.81	412,149	196,786	1,424,444	33.56	42,445
1999	2,209,747.79	641,435	306,261	2,455,924	34.55	71,083
2000	2,872,479.88	754,816	360,396	3,230,204	35.54	90,889
2001	3,258,447.00	766,631	366,038	3,707,021	36.53	101,479
2002	3,865,316.89	803,116	383,458	4,448,188	37.52	118,555
2003	5,087,693.18	917,184	437,921	5,921,695	38.51	153,770
2004	4,914,429.78	749,451	357,835	5,785,202	39.51	146,424
2005	5,525,175.28	689,127	329,032	6,577,437	40.51	162,366
2006	15,253,960.90	1,483,066	708,108	18,359,343	41.50	442,394
2007	12,257,740.35	851,300	406,464	14,915,711	42.50	350,958
2008	7,412,151.29	308,809	147,445	9,117,744	43.50	209,603
	98,456,667.81	33,500,147	15,995,063	107,075,772		4,360,892

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 24.6 4.43

FORTISBC, INC.

ACCOUNT 369.00 - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1975	313,088.38	141,265	313,088			
1976	322,649.96	141,537	322,650			
1977	406,239.51	173,111	406,240			
1978	335,038.66	138,572	335,039			
1979	180,407.47	72,331	180,407			
1980	385,727.31	149,766	385,727			
1981	528,602.68	198,474	528,603			
1990	1,461,568.98	378,064	1,461,569			
1991	2,157,049.05	529,491	2,157,049			
2006	1,202,026.00	56,099	385,480	816,546	71.50	11,420
	7,292,398.00	1,978,710	6,475,852	816,546		11,420

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 71.5 0.16

FORTISBC, INC.

ACCOUNT 370.00 - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R1						
NET SALVAGE PERCENT.. 0						
1960	2,416,785.74	2,295,946	2,123,318	293,468	1.00	293,468
1976	208.19	186	172	36	2.12	17
1977	31,865.46	27,994	25,889	5,976	2.43	2,459
1978	73,654.76	63,527	58,751	14,904	2.75	5,420
1979	62,424.10	52,811	48,840	13,584	3.08	4,410
1980	169,053.48	140,145	129,608	39,445	3.42	11,534
1981	219,202.68	177,883	164,508	54,695	3.77	14,508
1982	201,867.31	160,081	148,045	53,822	4.14	13,000
1983	132,651.28	102,672	94,952	37,699	4.52	8,340
1984	128,267.37	96,778	89,501	38,766	4.91	7,895
1985	163,022.00	119,658	110,661	52,361	5.32	9,842
1986	104,837.32	74,749	69,129	35,708	5.74	6,221
1987	275,366.00	190,278	175,971	99,395	6.18	16,083
1988	213,940.64	143,019	132,266	81,675	6.63	12,319
1989	312,549.79	201,595	186,437	126,113	7.10	17,762
1990	532,021.91	330,120	305,299	226,723	7.59	29,871
1991	425,815.70	253,573	234,507	191,309	8.09	23,648
1992	867,270.86	493,911	456,775	410,496	8.61	47,677
1993	634,291.97	344,103	318,231	316,061	9.15	34,542
1994	466,436.05	239,981	221,937	244,499	9.71	25,180
1995	293,083.77	142,439	131,729	161,355	10.28	15,696
1996	534,096.16	243,815	225,483	308,613	10.87	28,391
1997	557,665.23	237,565	219,703	337,962	11.48	29,439
1998	593,454.32	234,414	216,789	376,665	12.10	31,129
1999	472,965.89	171,923	158,997	313,969	12.73	24,664
2000	927,078.22	306,863	283,791	643,287	13.38	48,078
2001	415,575.04	123,841	114,529	301,046	14.04	21,442
2002	84,239.28	22,281	20,606	63,633	14.71	4,326
2003	732,930.18	168,940	156,238	576,692	15.39	37,472
2004	497,777.04	97,813	90,458	407,319	16.07	25,347
2005	304,581.00	49,342	45,632	258,949	16.76	15,450
2006	431,612.94	54,599	50,494	381,119	17.47	21,816
	13,276,591.68	7,362,845	6,809,246	6,467,346		887,446

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 7.3   6.68

FORTISBC, INC.

ACCOUNT 371.00 - INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R1						
NET SALVAGE PERCENT.. 0						
1981	34,384.33	27,903	34,384			
1982	36,229.42	28,730	36,229			
1983	42,518.49	32,909	42,518			
1984	16,078.90	12,132	16,079			
1985	52,719.75	38,696	52,720			
1986	8,980.84	6,403	8,981			
1987	25,148.56	17,378	25,149			
1988	32,351.82	21,627	32,352			
1990	5,199.58	3,226	5,200			
1991	5,210.15	3,103	5,210			
1992	626,480.82	356,781	626,481			
1993	7,791.55	4,227	7,792			
1994	6,679.42	3,437	6,679			
1995	3,104.62	1,509	3,105			
1998	34,953.75	13,807	34,953	1		
	937,832.00	571,868	937,832			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 0.0 0.00

FORTISBC, INC.

ACCOUNT 373.00 - STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 40-R4
NET SALVAGE PERCENT.. -5

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1960	7,258,412.32	7,114,514	1,310,643	6,310,690	2.66	2,372,440
1975	79,376.92	64,593	11,899	71,447	9.00	7,939
1976	104,987.34	83,587	15,398	94,839	9.67	9,808
1977	71,770.38	55,841	10,287	65,072	10.36	6,281
1978	106,714.55	81,040	14,929	97,121	11.07	8,773
1979	65,300.16	48,356	8,908	59,657	11.79	5,060
1980	67,097.78	48,383	8,913	61,540	12.53	4,911
1981	59,671.66	41,838	7,708	54,947	13.29	4,134
1982	50,779.95	34,564	6,367	46,952	14.07	3,337
1983	27,588.35	18,199	3,353	25,615	14.87	1,723
1984	35,077.35	22,384	4,124	32,707	15.69	2,085
1985	37,265.08	22,968	4,231	34,897	16.52	2,112
1986	8,659.78	5,142	947	8,146	17.38	469
1989	6,838.17	3,585	660	6,520	20.03	326
1992	95,705.52	43,211	7,961	92,530	22.80	4,058
1993	3,360.78	1,434	264	3,265	23.74	138
1994	419.62	169	31	410	24.69	17
1995	22,251.58	8,382	1,544	21,820	25.65	851
1996	21,967.77	7,716	1,421	21,645	26.62	813
1998	8,917.15	2,675	493	8,870	28.57	310
1999	45,688.16	12,521	2,307	45,666	29.56	1,545
2000	19,074.22	4,737	873	19,155	30.54	627
2001	79,960.00	17,778	3,275	80,683	31.53	2,559
2003	965,533.24	164,237	30,256	983,554	33.52	29,342
2004	886,418.00	127,744	23,534	907,205	34.51	26,288
2006	145,773.00	13,355	2,460	150,602	36.51	4,125
	10,274,608.83	8,048,953	1,482,786	9,305,553		2,500,071

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 3.7 24.33

FORTISBC, INC.

ACCOUNT 390.00 - STRUCTURES - FRAME AND IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. 0						
1970	4,441.25	3,519	4,441			
1975	8,477.77	6,144	8,478			
1976	1,884.54	1,337	1,885			
1977	505.63	351	506			
1978	14,502.63	9,829	14,503			
1979	4,764.19	3,149	4,764			
1980	46,096.68	29,675	46,097			
1981	2,642.09	1,655	2,642			
1982	857.56	522	858			
1983	4,450.46	2,626	4,450			
1984	2,179.00	1,245	2,179			
1985	15,136.67	8,359	15,137			
1986	5,520.20	2,941	5,520			
1987	8,070.07	4,140	8,070			
1988	32,576.54	16,052	32,577			
1989	19,930.71	9,417	19,409	522	21.10	25
1990	5,285.55	2,388	4,922	364	21.93	17
1992	4,967.87	2,033	4,190	778	23.63	33
1993	7,095.84	2,751	5,670	1,426	24.49	58
1994	27,354.25	10,005	20,620	6,734	25.37	265
1995	6,893.99	2,368	4,881	2,013	26.26	77
1996	8,329.76	2,676	5,515	2,815	27.15	104
1997	11,704.28	3,494	7,201	4,503	28.06	160
1998	2,204.69	607	1,251	954	28.98	33
1999	18,596.12	4,696	9,679	8,917	29.90	298
2000	7,032.66	1,612	3,322	3,711	30.83	120
2001	65,863.00	13,551	27,929	37,934	31.77	1,194
	337,364.00	147,142	266,696	70,668		2,384

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 29.6 0.71

FORTISBC, INC.

ACCOUNT 390.10 - STRUCTURES - MASONRY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 35-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1975	496,561.44	392,994	128,574	367,987	7.30	50,409
1976	98,360.00	76,439	25,008	73,352	7.80	9,404
1979	2,059,296.91	1,503,287	491,823	1,567,474	9.45	165,870
1980	0.06	0	0			
1983	662,652.46	435,648	142,529	520,123	11.99	43,380
1985	1,710,535.48	1,056,136	345,530	1,365,005	13.39	101,942
1986	76,557.00	45,672	14,942	61,615	14.12	4,364
1987	1,262,134.00	726,270	237,610	1,024,524	14.86	68,945
1988	746,503.00	413,137	135,164	611,339	15.63	39,113
1989	379,258.00	201,549	65,940	313,318	16.40	19,105
1991	139,875.00	67,939	22,227	117,648	18.00	6,536
1992	151,132.00	69,823	22,844	128,288	18.83	6,813
1993	292,864.00	128,359	41,995	250,869	19.66	12,760
1994	93,128.00	38,555	12,614	80,514	20.51	3,926
1999	67,804.00	19,469	6,369	61,435	24.95	2,462
2000	5,267.00	1,374	450	4,817	25.87	186
2001	232,816.00	54,546	17,845	214,971	26.80	8,021
2003	196,800.04	35,481	11,608	185,192	28.69	6,455
2007	260,282.00	18,220	5,961	254,321	32.55	7,813
	8,931,826.39	5,284,898	1,729,033	7,202,793		557,504

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 12.9 6.24

FORTISBC, INC.

ACCOUNT 390.20 - OPERATIONS BUILDINGS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. 0						
1979	7,816,292.74	5,705,894	2,080,875	5,735,418	9.45	606,923
2003	4,933,835.51	889,521	324,398	4,609,438	28.69	160,664
	12,750,128.25	6,595,415	2,405,273	10,344,855		767,587

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 13.5   6.02

FORTISBC, INC.

ACCOUNT 391.00 - OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
1985	54,039.39	50,437	54,039			
1998	2,561,379.01	1,963,732	2,411,360	150,019	3.50	42,863
1999	284,447.00	199,113	244,500	39,947	4.50	8,877
2000	128,875.00	81,620	100,225	28,650	5.50	5,209
2001	144,211.00	81,720	100,348	43,863	6.50	6,748
2002	202,331.03	101,166	124,227	78,104	7.50	10,414
2003	451,130.69	195,488	240,049	211,082	8.50	24,833
2004	601,075.73	220,396	270,634	330,442	9.50	34,783
2005	314,887.27	94,466	115,999	198,888	10.50	18,942
2006	242,960.20	56,690	69,613	173,347	11.50	15,074
2007	248,080.29	41,348	50,773	197,307	12.50	15,785
2008	236,641.24	23,664	29,058	207,583	13.50	15,377
2009	5,119.92	171	210	4,910	14.50	339
	5,475,177.77	3,110,011	3,811,035	1,664,143		199,244

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 8.4 3.64

FORTISBC, INC.

ACCOUNT 391.10 - COMPUTER EQUIPMENT AND SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
1994	218,967.68	197,071	218,968			
1995	424,200.51	381,780	424,201			
1996	395,202.00	355,682	395,202			
1997	363,002.00	326,702	363,002			
1998	5,442,637.00	4,898,373	5,442,637			
1999	394,191.00	354,772	394,191			
2000	206,947.22	186,252	206,947			
2002	8,742,268.96	6,556,702	8,254,409	487,860	2.50	195,144
2003	1,284,447.63	834,891	1,051,067	233,381	3.50	66,680
2004	356,899.97	196,295	247,121	109,779	4.50	24,395
2005	1,496,275.23	673,324	847,666	648,609	5.50	117,929
2006	1,382,866.62	484,003	609,324	773,543	6.50	119,007
2007	1,650,874.70	412,719	519,583	1,131,292	7.50	150,839
2008	6,530,657.12	979,599	1,233,244	5,297,413	8.50	623,225
2009	3,068,103.93	153,405	193,126	2,874,978	9.50	302,629
	31,957,541.57	16,991,570	20,400,688	11,556,854		1,599,848

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 7.2 5.01

FORTISBC, INC.

ACCOUNT 391.20 - PC COMPUTER EQUIPMENT AND SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
1994	56,834.00	45,467	41,209	15,625	1.00	15,625
1995	114,958.00	91,966	83,353	31,605	1.00	31,605
1996	580,755.35	464,604	421,090	159,665	1.00	159,665
1997	243,398.00	194,718	176,481	66,917	1.00	66,917
1998	2,933,838.00	2,347,070	2,127,246	806,592	1.00	806,592
1999	416,862.00	333,490	302,256	114,606	1.00	114,606
2000	4,169,357.20	3,335,486	3,023,088	1,146,269	1.00	1,146,269
2001	2,113,030.00	1,690,424	1,532,101	580,929	1.00	580,929
2002	669,968.26	535,975	485,776	184,192	1.00	184,192
2003	861,086.83	688,869	624,350	236,737	1.00	236,737
2004	725,775.97	580,621	526,241	199,535	1.00	199,535
2005	1,405,882.45	1,124,706	1,019,367	386,515	1.00	386,515
2006	4,222,324.07	2,955,627	2,678,806	1,543,518	1.50	1,029,012
2007	1,056,865.25	528,433	478,940	577,925	2.50	231,170
2008	2,589,121.76	776,737	703,989	1,885,133	3.50	538,609
2009	2,768,964.77	276,896	250,962	2,518,003	4.50	559,556
	24,929,021.91	15,971,089	14,475,255	10,453,767		6,287,534

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 1.7 25.22

FORTISBC, INC.

ACCOUNT 392.10 - LIGHT DUTY VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 8-L3						
NET SALVAGE PERCENT.. +20						
1989	22,790.00	15,953	1,375	16,857	1.00	16,857
1990	28,215.00	19,750	1,702	20,870	1.00	20,870
1994	23,542.00	16,479	1,420	17,414	1.00	17,414
1995	201,795.00	141,256	12,174	149,262	1.00	149,262
1996	23,190.00	15,908	1,371	17,181	1.14	15,071
2003	15,488.00	8,147	702	11,688	2.74	4,266
2004	87,107.00	42,073	3,626	66,060	3.17	20,839
2005	1,667,280.93	696,923	60,066	1,273,759	3.82	333,445
2006	2,204,153.00	742,800	64,020	1,699,302	4.63	367,020
2007	1,199,672.00	295,119	25,436	934,302	5.54	168,647
2008	1,035,611.85	155,342	13,388	815,101	6.50	125,400
2009	257,707.22	12,885	1,111	205,055	7.50	27,341
	6,766,552.00	2,162,635	186,391	5,226,851		1,266,432

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 4.1   18.72

FORTISBC, INC.

ACCOUNT 392.20 - HEAVY DUTY VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L3						
NET SALVAGE PERCENT.. +20						
1971	17,435.00	12,686	13,330	618	1.81	341
1972	43,735.00	31,454	33,050	1,938	2.02	959
1978	57,110.00	37,967	39,893	5,795	3.38	1,714
1979	11,705.00	7,664	8,053	1,311	3.63	361
1980	78,670.00	50,726	53,299	9,637	3.88	2,484
1981	2.87	2	2			
1982	52,341.00	32,661	34,318	7,555	4.40	1,717
1983	34,698.00	21,291	22,371	5,387	4.66	1,156
1984	36,718.00	22,163	23,287	6,087	4.91	1,240
1985	120,154.00	71,371	74,992	21,131	5.15	4,103
1987	208,222.00	120,186	126,283	40,295	5.57	7,234
1988	0.03	0	0			
1989	28,561.96	16,086	16,902	5,948	5.92	1,005
1990	483,990.00	269,292	282,954	104,238	6.09	17,116
1991	24,193.00	13,287	13,961	5,393	6.27	860
1992	338,790.00	183,082	192,370	78,662	6.49	12,120
1993	49,387.00	26,136	27,462	12,048	6.77	1,780
1994	520,606.23	268,425	282,043	134,442	7.11	18,909
1995	391,477.00	195,112	205,011	108,171	7.54	14,346
1996	63,066.00	30,120	31,648	18,805	8.06	2,333
1999	47,496.00	18,770	19,722	18,275	10.12	1,806
2000	78,355.00	28,396	29,837	32,847	10.94	3,002
2002	304,829.00	89,132	93,654	150,209	12.69	11,837
2003	123,799.00	31,643	33,248	65,791	13.61	4,834
2004	174,545.00	37,981	39,908	99,728	14.56	6,849
2005	758,198.02	135,869	142,762	463,796	15.52	29,884
2006	1,075,395.00	150,125	157,742	702,574	16.51	42,554
2007	3,186,134.99	318,613	334,778	2,214,130	17.50	126,522
2008	669,066.61	40,144	42,181	493,072	18.50	26,653
2009	1,807,008.78	36,140	37,973	1,407,634	19.50	72,186
	10,785,689.49	2,296,524	2,413,034	6,215,518		415,905

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 14.9 3.86

FORTISBC, INC.

ACCOUNT 394.00 - TOOLS AND WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
1978	30,528.52	28,493	30,529			
1979	67,863.00	63,339	67,863			
1980	80,643.00	75,267	80,643			
1981	72,218.00	67,403	72,218			
1982	77,142.00	71,999	77,142			
1983	65,245.00	60,895	65,245			
1984	115,409.00	107,715	115,409			
1985	473,348.43	441,790	473,348			
1986	198,825.00	185,569	198,825			
1987	120,168.00	112,156	120,168			
1988	175,882.00	164,156	175,882			
1989	404,733.00	377,749	404,733			
1990	206,564.00	192,792	206,564			
1991	223,808.00	208,887	223,808			
1992	160,370.00	149,678	160,370			
1993	288,316.00	269,094	288,316			
1995	215,015.00	200,680	215,015			
1996	88,890.00	80,001	88,890			
1997	461,604.00	384,668	438,983	22,621	2.50	9,048
1998	498,925.00	382,511	436,521	62,404	3.50	17,830
1999	545,506.00	381,854	435,772	109,734	4.50	24,385
2000	351,604.00	222,681	254,123	97,481	5.50	17,724
2001	664,907.00	376,783	429,985	234,922	6.50	36,142
2002	449,257.79	224,629	256,347	192,911	7.50	25,721
2003	514,101.97	222,776	254,232	259,870	8.50	30,573
2004	518,418.44	190,088	216,928	301,490	9.50	31,736
2005	758,607.61	227,582	259,717	498,891	10.50	47,513
2006	859,648.67	200,582	228,904	630,745	11.50	54,847
2007	936,499.18	156,086	178,125	758,374	12.50	60,670
2008	587,124.42	58,712	67,002	520,122	13.50	38,528
2009	657,856.91	21,926	25,022	632,835	14.50	43,644
	10,869,028.94	5,908,541	6,546,629	4,322,400		438,361

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 9.9 4.03

FORTISBC, INC.

ACCOUNT 397.00 - COMMUNICATIONS STRUCTURES AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
1977	15,726.00	14,678	13,059	2,667	1.00	2,667
1978	42,197.00	39,384	35,039	7,158	1.00	7,158
1979	48,433.00	45,204	40,217	8,216	1.00	8,216
1980	66,469.00	62,038	55,193	11,276	1.00	11,276
1982	39,708.00	37,061	32,972	6,736	1.00	6,736
1983	97,820.00	91,298	81,225	16,595	1.00	16,595
1984	166,808.00	155,687	138,510	28,298	1.00	28,298
1985	52,071.00	48,599	43,237	8,834	1.00	8,834
1986	33,009.00	30,808	27,409	5,600	1.00	5,600
1987	28,033.00	26,164	23,277	4,756	1.00	4,756
1988	168,129.52	156,920	139,607	28,523	1.00	28,523
1989	3,077.00	2,872	2,555	522	1.00	522
1990	115,099.00	107,425	95,573	19,526	1.00	19,526
1991	135,481.00	126,448	112,497	22,984	1.00	22,984
1992	221,699.00	206,918	184,088	37,611	1.00	37,611
1993	61,008.00	56,941	50,659	10,349	1.00	10,349
1994	105,674.00	98,629	87,747	17,927	1.00	17,927
1995	193,317.00	180,429	160,522	32,795	1.00	32,795
1996	916,634.00	824,971	733,950	182,684	1.50	121,789
1997	591,987.00	493,321	438,891	153,096	2.50	61,238
1998	264,756.00	202,980	180,585	84,171	3.50	24,049
1999	569,024.00	398,317	354,370	214,654	4.50	47,701
2000	114,826.00	72,723	64,699	50,127	5.50	9,114
2001	212,907.00	120,648	107,337	105,570	6.50	16,242
2002	29,998.55	14,999	13,344	16,655	7.50	2,221
2003	2,752,554.17	1,192,764	1,061,163	1,691,391	8.50	198,987
2004	315,586.15	115,716	102,949	212,637	9.50	22,383
2005	5,360,030.39	1,608,009	1,430,592	3,929,438	10.50	374,232
2006	1,710,297.18	399,064	355,034	1,355,263	11.50	117,849
2007	5,528,980.52	921,515	819,842	4,709,139	12.50	376,731
2008	1,653,946.22	165,395	147,146	1,506,800	13.50	111,615
2009	1,083,117.36	36,100	32,117	1,051,000	14.50	72,483
	22,698,403.06	8,054,025	7,165,405	15,532,998		1,827,007

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 8.5   8.05

Appendix K

2011 SAFETY PLAN

Table of Contents

List of Appendices

Index of Tables and Figures

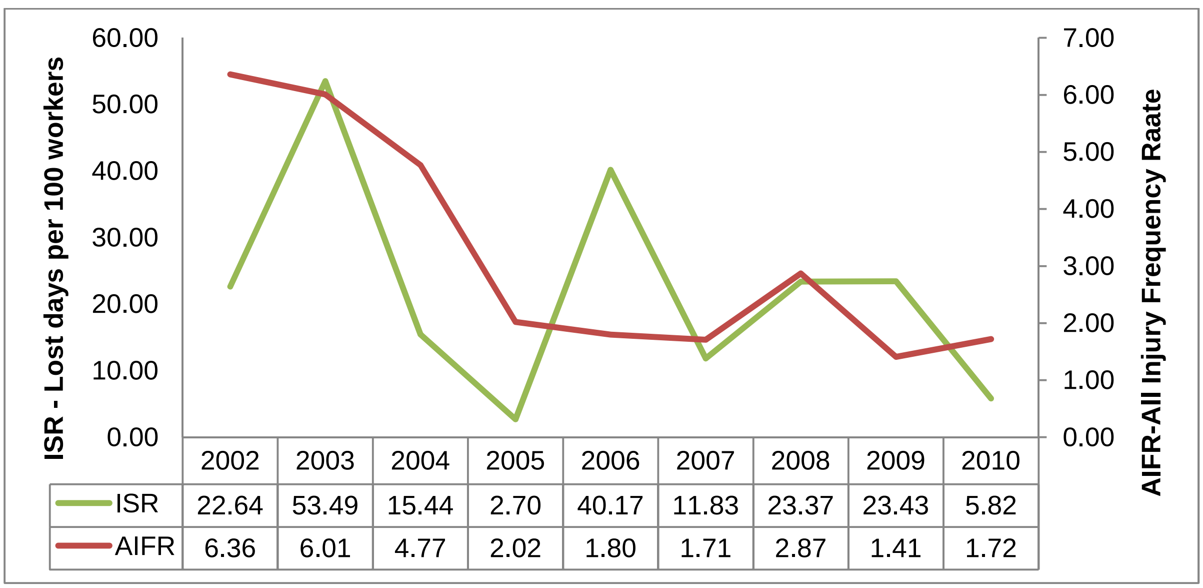
1. INTRODUCTION

FortisBC strives for excellence in safety performance. The Company's primary goal is to ensure that every single day our employees return home safely to their families and loved ones. The Company conducts ongoing reviews of safety performance including standards, procedures and processes, training, investigations of incidents, timely recommendations for improvements, and provides employees with approved safety equipment to further mitigate potential hazards.

FortisBC's Corporate Policy Statement on Health and Safety is provided as Appendix A. The Company has maintained its focus on safety since 2004 with appropriate resources associated with safety. The Company utilizes a Safety Management System to provide structure and support for the safety initiative through the Company. Management system audits indicate that continual improvement is being realized. The Company engaged an external certified independent auditor to audit the Company's Safety System in May 2009. The audit was based on the national standard protocol used by the Construction Safety Association of BC (CSABC). The audit produced a 99 percent score indicating the safety system is functioning as expected.

This report provides a description of the Company's Safety Management System and sets out how FortisBC manages its safety program to provide a safe working environment for its employees.

Figure 1.0 FortisBC Injury Frequency and Severity Rates (2002-2010)



	2002	2003	2004	2005	2006	2007	2008	2009	2010
ISR	22.64	53.49	15.44	2.70	40.17	11.83	23.37	23.43	5.82
AIFR	6.36	6.01	4.77	2.02	1.80	1.71	2.87	1.41	1.72

2. FORTISBC SAFETY PROGRAM OVERVIEW

2.1 Plan Overview

FortisBC's Safety Management System follows the concept of Plan/Do/Check/Act of many management systems. It is a dynamic process in which all portions of the system involve the concept of 'continual improvement.' FortisBC initiates and supports this process through the 5 key elements of the management system:

- Policy: Senior management setting clear policy and guidelines for performance;
- Planning: Identifying issues and requirements, setting performance objectives and planning the execution of work;
- Implementation and Operation: The achievement of objectives and the execution of work;
- Checking and Improvement: Performance assessment and review and making changes to improve performance; and
- Stakeholder Review: Closing the loop with feedback to corporate policy and goals.

The concept of continual improvement for all the key elements is supported by the following commitments:

- Making safety part of core values;
- Education and training;
- Improving safety performance by use of incident experiences; and
- Incorporating safety management principles and practices in all phases of the business.

2.2 Safety Structure

The safety department reports to senior management through a Safety Director. The safety staff consists of a Safety Superintendent, Safety Coordinators and a support staff.

Maintaining the Safety Program at the field level involves managing various activities through a process of annual planning and review. It is the responsibility of the operational managers to plan and review safety activities to confirm that the departmental Safety Program is being effectively managed. The managers in cooperation with the Local Safety Team prepare a Safety Activity Schedule which lists safety meetings, inspections, maintenance of safety equipment and education activities. A safety meeting improvement opportunity was identified and implemented in 2010. The safety meeting protocol has been updated to better reflect the continual improvement model and bring more hazard identification and control opportunities to workers. Figure 2.4 below outlines the Safety Information Meeting (SIM) terms of reference. Appendix E outlines the Safety Structure Flow.

Figure 2.2 Safety Information Meeting Terms of Reference

Purpose:

The Safety Information Meeting is a **mandatory** requirement of FortisBC's Health and Safety Program to formally:

1) Inform / educate employees of the Health, Safety & Environment Corporate standards (HSE).
2) Inform / educate employees of Safety Practice Rules & Regulations (SPR).
3) Review relevant incident/accident investigations.
4) Inform/educate employees of new or revised Regulations.
5) Inform employees of current Safety Bulletins.
6) Review Safety Awareness training topics.
7) Document the above and ensure attendance is recorded with signatures.

Method of Delivery:

The Safety Information Meeting will be delivered to employees by the immediate Supervisor or a designate responsible for the area/department at a designated report location.

Frequency:

The Safety Information Meeting shall be held a minimum of once per month or at a frequency required to ensure employees are informed/educated on any updates to FortisBC SPR's or other applicable Regulations or Standards.

The managers in cooperation with the Local Safety Team prepare a Safety Activity Schedule which establishes safety meetings, inspections, crew observations, maintenance of safety equipment and education activities.

3. PERFORMANCE MEASURES

Safety performance measures are based on general industry standards. The Company looks to improve its performance compared to itself year to year. While the Company does not directly compare itself to the Canadian Electric Association (CEA), the composite numbers are provided for reference. The charts below indicate Company performance versus CEA composite performance statistics based on a January to December calendar year.

Table 3.1 All Injury Frequency Rate per 100 workers

	2002	2003	2004	2005	2006	2007	2008	2009	2010
FortisBC	6.36	6.01	4.77	2.02	1.80	1.71	2.87	1.41	1.72
CEA Composite	3.47	3.41	3.48	2.76	2.84	3.01	2.88	2.15	2.09

FortisBC has reduced injuries to maintain a better than average rate since 2005.

Table 3.2 FortisBC Recordable Injuries

	2002	2003	2004	2005	2006	2007	2008	2009	2010
FortisBC	25	21	17	9	10	10	13	6	8

Fewer injuries indicates positive trend.

Table 3.3 Injury Severity Rate per 100 workers

	2002	2003	2004	2005	2006	2007	2008	2009	2010
FortisBC	22.64	53.49	15.44	2.70	40.17	11.83	23.37	23.43	5.82
CEA Composite	32.18	24.31	22.18	17.67	17.60	16.13	21.10	15.73	13.70

FortisBC has been trending towards lesser severity since 2004.

Table 3.4 Vehicle Incident Rate (VIR) per One Million Kilometers

	2003	2004	2005	2006	2007	2008	2009	2010
FortisBC	5.54	5.4	2.79	1.82	1.73	2.36	2.71	1.22
CEA Composite	3.48	3.72	2.06	2.13	2.44	2.67	2.67	1.59

FortisBC's performance has been better (fewer collisions) than the CEA average since 2006, with one exception.

4. TRAINING

The Company considers safety to be the most important part of the work process. Workers are regularly trained in Safety Practice Rules, Safety Manual, applicable procedures and practices.

Training employees to know how to do their jobs safely with minimal risk to their health is undertaken to keep workers safe and healthy. Well trained, competent workers perform their jobs safely and are more productive.

New and transferred worker orientation and training is mandatory to ensure trained and competent employees are on the job. Table 4.1 below shows the number of training courses and the number of individual training occurrences undertaken by all FortisBC employees since 2006. A summary of the courses provided in 2010 is provided in Appendix D.

Table 4.1 Training

	2006	2007	2008	2009	2010
Training Courses	79	167	159	299	267
Individual training occurrences	3,224	3,671	4,192	4,735	5,448

Up to date records are maintained by the Company through the Utility Risk Management System, identifying the instruction or training received, the date it was provided and when/if follow up training is required.

5. MONITORING

Regular workplace audits, inspections and crew visits are performed to maintain safe working conditions and confirm the use of safe work practices. Managers conduct inspections of work performed under their authority (including work performed by contractors) to confirm that safe working conditions are maintained and safety practices are understood and being applied. Specific inspections may be performed by employees assigned by the manager. A system of inspections makes looking for hazards a normal part of everyday work and two important pieces of information about the work site:

1. Information about hazards or potential hazards that have not been noted previously; and
2. Check the effectiveness of controls for eliminating or reducing the risk of known hazards is confirmed.

The Crew Visit form is attached as Appendix B. Inspections and crew observations are captured in Utility Risk Management system. Formal inspections and observations created 877 opportunities to deal with hazards in a proactive manner in 2010.

Audits are used to measure success and evaluate the program. Audits provide opportunities to identify areas where improvements may make the safety program more effective. In December 2006, as part of its continual improvement process, the Company engaged an external certified independent auditor to audit the Company's safety system following a WorkSafeBC Partnerships audit format. The audit received a 75 percent compliance score. Areas and opportunities for improvement were identified and implemented.

The Company initiated a follow-up audit in November 2007. The follow-up audit received a score of 98 percent indicating the high capability and quality of the overall safety management system. Management developed and implemented a plan to address issues identified in the November 2007 audit. The plan was implemented throughout 2008 to complete the continuous improvement goals.

The Company commissioned an audit of the safety system in May 2009. The audit produced a 99% score indicating the safety system is functioning as expected. The next safety audit is scheduled for late 2011.

Shown below is a detailed audit result for 2009.

1 **Figure 5.1 2009 Safety Audit**

CSABC The Construction Safety Association of British Columbia

AUDIT SUMMARY SHEET

Company: ________ Name of Auditor: ________ Date of Audit: ________

Section #	Section Name	Possible Score	Actual Score	Minimum Standard	Section Percentage
1	Company Health and Safety Policy	27	27	14	100
2	Workplace Hazard Assessment and Control	44	44	22	100
3	Safe Work Practices	16	16	8	100
4	Safe Job Procedures	16	16	8	100
5	Company Rules	9	9	5	100
6	Personal Protective Equipment	18	18	9	100
7	Preventative Maintenance	12	12	6	100
8	Training and Communication	42	42	21	100
9	Inspections	30	30	15	100
10	Investigations and Reporting	30	27	15	90
11	Emergency Preparedness	28	28	14	100
12	Records and Statistics	18	18	9	100
13	Legislation	12	12	6	100
14	Joint Health and Safety Committee or Worker Health and Safety Representative	12	12	6	100
	Total	314	311		

Appendix A

CORPORATE POLICY STATEMENT

Appendix A
Corporate Policy Statement

May 2005

Health & Safety

The Company will not compromise employee and public safety and will strive for excellence in safety performance. FortisBC's primary goal is to ensure that every single day our employees return home safely to their family and loved ones. In fulfilling this commitment, the Company shall provide a safe and healthy workplace in compliance with relevant legislative requirements and in accordance with leading industry practices and standards.

- Health and Safety are personal and are the responsibility of all employees. Each employee must protect his or her health and safety and the safety of others by following established safety practices and procedures. Employees will be trained to safely fulfill their duties.
- No work requirement is more important than ensuring the job is performed safely Short cuts for expediency, at the expense of health and safety, are unacceptable.
- Supervisors are accountable for the health and safety of employees under their supervision.
- The Company will make every reasonable effort to eliminate hazards and minimize risks that have the potential to threaten health and safety.
- The Company will ensure it has an effective health and safety management system, and will conduct assessments of its health and safety system in order to strive for continual improvement in performance.
- Contractors are also required to comply with all legislative requirements, recognized industry practices and Company Health and Safety Standards.
- The Company will educate the public in both the area of electrical safety and on its safety policies and initiatives.

FORTISBC

President and Chief Executive Officer

Appendix B

CREW VISIT

Department:	Location:	Date:	Time:
Chargehand/Lead Hand:	Crew Members:		
Brief Description:			

SAFE WORK PERFORMANCE ASSESSMENT

N/A = not applicable Y = yes Blank = no

Job Plan/Tailboard Conference: ☐ ☐ written ☐ ☐ well prepared ☐ ☐ well communicated ☐ ☐ hazards/barriers/u-g locates ☐ ☐ emergency preparedness	Observations:	Action Required (Class 1, 2 or 3): Person Responsible: Action Completed: ☐
Vehicle Set-up: ☐ ☐ location ☐ ☐ braking device ☐ ☐ chocks/outrigger pads/ grounding ☐ ☐ Log books/pre-trip	Observations:	Action Required: Person Responsible: Action Completed: ☐
Traffic Control: ☐ ☐ road signs ☐ ☐ cones ☐ ☐ flashers ☐ ☐ flag persons ☐ ☐ barriers	Observations::	Action Required: Person Responsible: Action Completed: ☐
Personal Protective Equipment ☐ ☐ footwear ☐ ☐ vest/coveralls/FR ☐ ☐ hard hats ☐ ☐ eye protection ☐ ☐ hearing protection ☐ ☐ chainsaw pants/fall arrest	Observations:	Action Required: Person Responsible: Action Completed: ☐ Action Completed:
Work Protection: ☐ ☐ Lockout forms used ☐ ☐ tags ☐ ☐ grounding/bonding	Observations:	Action Required:

☐ ☐ Station Log Book		Person Responsible: Action Completed: ☐ Action Completed: ☐
Work Practices: ☐ ☐ no excessive body strain ☐ ☐ work not rushed ☐ ☐ enough people for job	Observations::	Action Required: Person Responsible: Action Completed: ☐
Work Methods and Procedures: ☐ ☐ rubber gloves ☐ ☐ fall arrest ☐ ☐ cover-up ☐ ☐ rigging ☐ ☐ Limits of Approach ☐ ☐ Engineering Standards ☐ ☐ written work procedures	Observations:	Action Required: Person Responsible: Action Completed: ☐
Equipment: ☐ ☐ good condition ☐ ☐ appropriate for job ☐ ☐ tools used properly	Observations:	Action Required: Person Responsible: Action Completed: ☐
Other Observations:	Observations:	Action Required: Person Responsible: Action Completed: ☐

Conducted By:_______________________________________

Appendix C

JOB PLANNING, RISK ASSESSMENT AND INSTRUCTION

JOB PLANNING, RISK ASSESSMENT AND INSTRUCTION

1. Preamble

1.1 The work environment in the utility industry exposes workers to hazards daily and requires frequent changes in work location, crew complement and work procedures. Utilities require extensive safe work planning process in which safety is incorporated into the design and implementation phases and job plans are effectively communicated to all team members.

2. Standard

2.1 Purpose

Job planning and risk assessment is a systematic examination of all aspects of the work undertaken to consider what could cause injury or harm, whether the hazards could be eliminated and if not, what prevention or protection measures are or should be in place to control risk. Expected outcomes:

- reduce the risk of serious accidents
- provide a better opportunity to identify and control hazards before the work begins
- improve the quality of construction drawings and integrate safety into the design phase
- improve the communication between engineering planners, supervisors, and crew members
- more effectively manage changes that occur during a project or job

2.2 Job Planning Documents

General Risk Assessment:

- Required to manage critical risks and areas specified by OHS Regulation.

Tailboard Conference Plan (Safe Work Plan):

- Required to complement the tailboard discussions for all daily job tasks.

The plan will be prepared by the working crew at the job site at the beginning of the job to ensure site specific hazards and conditions are **identified and controlled**. If tasks, procedures, or plans change during the course of the day it will be necessary to hold a new tailboard conference. These Tailboards shall all be recorded in the standard format and the discussion shall include all of the affected crew including any crew members who join the job while in progress. The completed Tailboard Conference Plan must be filed on completion of the job and those files must be accessible to others. (See Section 2.5 of this Standard for more information on filing).

Steps and Conditions Plan or a Job Steps Plan is required for all significant projects, maintenance activities and/or inspections. The plan will be prepared with sufficient lead time to allow modifications to the construction drawings if required and will be issued with the job planning folder. Usually a Steps and Conditions plan is used on larger jobs (defined as greater than one week in duration or jobs involving multiple crews). A Job Steps plan is used for medium sized jobs (a week or less in duration), whereas a written tailboard (Safe Work Plan) can be used as the job plan for small jobs (one day or less). These are guidelines based on job duration but may need to be upgraded depending on the complexity or hazard of the work being considered.

For certain potentially hazardous work, such as stringing in proximity to energized conductors, a Steps and Conditions Plan or Job Steps Plan is always required, regardless of the duration of the job.

A Job Planning Package/Folder is required for all significant projects, maintenance activities and/or inspections. Smaller projects may only require the tailboard document as the job planning package, depending on the complexity of the work involved. The package/folder will contain all documents relevant to the project such as construction drawings, standard work procedures, material lists, schedule, job orders, emergency response plans, etc. In some cases this package/folder may become an integral part of the construction package. A standard job planning process/document will be given to all field related employees as a guideline or procedure for formulating a Job Planning Package. A Job Plan Folder, preprinted with useful reference information will be made available for holding the components of the Job Planning Package.

Responsible staff WILL be provided with sufficient time and resources to prepare the job planning documents and communicate the plans to the crews involved.

IT IS CRITICALLY IMPORTANT TO UNDERSTAND THAT SAFETY RISK MANAGEMENT IS A TWO-STEP PROCESS: HAZARD IDENTIFICATION **AND** Control (Elimination and BARRIER IMPLEMENTATION).

2.3 Responsibilities

The Department Director is accountable to establish the job planning process, to develop and communicate the job planning guidelines to the staff and to establish a system to monitor the quality and effectiveness of the job planning within the department.

Managers, Supervisors, Foremen (including chargehands) are responsible for the ongoing management of the job planning process. They must designate resources and time for planning, ensuring that sufficient lead time is provided and regularly monitor the job planning process.

General responsibility for each stage of the planning process must be described in a procedural document for each department.

2.4 Criteria for Conducting Tailboard Conferences – Safe Work Plan

- A tailboard conference must be held every day and at every new job before the work begins. This includes emergency jobs and after-hours call-outs.
- A written Tailboard Conference Plan is required to facilitate the tailboard discussions and should be prepared by the crew supervisor at the job site before the work begins. A Tailboard Conference Plan must be filled out even if you are the only person on the job. The hazards still exist and the barriers must be implemented to keep you safe.
- If the conditions at the job site have not changed, the crew can use the same written Tailboard Conference Plan for the same job on successive days. The crew supervisor and crew must date and initial the plan in the space provided for this purpose each day to indicate that it was used during the tailboard discussion that day. Each crew member is to initial the tailboard document acknowledging his/her presence and understanding.
- For smaller jobs conducted at several locations during one day, a written Tailboard Conference Plan must be prepared for the first job of the day. A review of the plan is required whenever the location or job scope changes to determine if there are significant changes to the written plan.

All areas of the Tailboard Conference Plan should be filled out.

This document must define:

- WHAT work is being done
- WHERE it is being carried out
- WHO is on the crew
- WHEN the job is being done
- WHAT major hazards might be encountered
- WHAT barriers will be in place to control those hazards
- WHAT to do if an emergency situation occurs during the job

The form is designed to answer all of these questions. They are not optional

2.5 Monitoring the Job Planning Process

Managers, supervisors, foremen, lead hands, charge-hands and worker in charge (senior worker) must review the preparation and quality of the written job plans during regular crew visits and provide immediate constructive feedback to the work crews.

When the job is complete, the tailboard conference plans must be retained in the project folder and returned to the charge-hand/supervisor who will ensure the project folder is properly filed.

2.6 Job Planning Process

Attached to this standard are two charts (one for T&D projects and one for Generation projects) depicting the job planning process steps with assignment of responsibilities for each step. These steps are intended for use on larger jobs.

Appendix D

TRAINING COURSE LIST

TRAINING COURSE LIST

Safety and Environment Courses

2010 courses delivered
3M Cable Splicing / Terminations
AED Training
AED-Refresher (includes CPR Review)
Applied Risk Communication Skills
Arc Flash Hazard Awareness & FR Clothing
Asbestos Awareness - Refresher
Bucket Rescue
Bucket Self Rescue
CAT 2 - Access the Power System
CAT 2 - Non Field - Access the Power System (Basic)
CAT 3- System Safety/Lockout-Power Systems
CAT 5 - Lockout
Chainsaw - Storm Season Training
Chainsaw Operation & Safety
Composite Insulators
Confined Space Awareness
Confined Space Entry
Conveyancing Procedures
Corporate New Hire Orientation
Crane Inspection - O/H Power House
Credit Basics
Develop a Supply Chain Mgmt. Strategic Plan
Dog Bite Prevention
DOT Load Securement
Driving Safety (seasonal)
Due Diligence for Employers
Due Diligence for Managers & Supervisors
Effective Safety Structure
Electric Utility Systems for Non-Engineers
Environmental Awareness
EpiPen Awareness
Equipment Service Training/Refresher
Ergonomics - Back Care Prevention (Safe Lifting)
Ergonomics - Office
Ethics, Rules & Standards for New CGAs

2010 courses delivered
Fall Protection - DBI SALA
Fire Extinguishers
First Aid - Level 1 - WCB Occupational
First Aid - Level 2- WCB Occupational
First Aid- Level 3 - WCB Occupational
First Aid Transportation Endorsement
Forklift Counterbalance
Formal Language (Operating Communication)
Front End Loader-John Deere
Hazardous Waste Training (Part of EMS)
Hazardous Waste Ops & Emergency Response
Heat Related Illness (seasonal)
Helicopter Safety
Hilti Powder Actuated Tools
Hot Stick and Protective Cover-up
Incident Investigation
Incident Report Procedures
Invasive Plants-Noxious Weed Best Mgmt. Practices
ION Meter Programmer - Schneider Electric Course
Joint Health & Safety Training
Law & Ethics
Lead Abatement
Leadership: Corporate Orientation for Leaders
Leadership: Creative Coaching
Leadership: Incident Investigation-Due Diligence
Leadership: The Toolbox
Manlift - Aerial Platform
Meter Check Methods
MS Exchange Server-Configuring, Managing, Trouble
MS Projects 2007
MS Visio 2007
MS Word Part 2 - 2007
Oil Spill Containment Awareness
Overcurrent Protection of Power Systems
PIC Transfer Training - Pilot Project
Pole Top Rescue
Polish your Prof. Writing Skills
Presentation Refresher Training

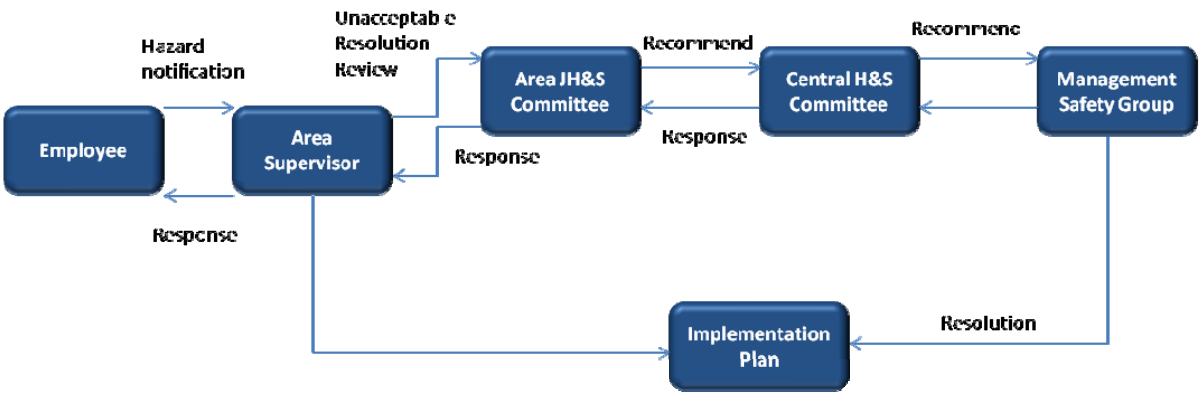
2010 courses delivered
Quality Assurance
Reduce Economic & Human Challenges of Disability
Reliability Evaluation of Electric Power Systems
Respirator Fit Test
Rigging - Advanced
Rigging - Line Trade
Rigging Overview-Knuckle Boom Truck
Risk Assessment
Rubber Glove - Qualified
S - SPR 200
S - SPR 300
S - SPR 400
Safe Work Planning
SAP Purchase Order Training
SharePoint
Sharps Awareness
Site Orientation
Small Wastewater System
Small Water System & Waste Mgmt. Operator Certificate
SnoCat Training
Snowmobile Awareness
SPR 100
SPR 200
Technical - Grounding & Electromagnetic Fields
Teck Cominco Induction - Warfield
Tension Stringing - Overhead
Transformer Training-3D Simulator
Transportation Dangerous Goods (TDG)
Underground (URD) Operating Procedures
URM Incident Management Module Training
Utility Fleet Mechanic Training
VHF Radio Procedures
WHMIS
WHMIS Refresher
Wildlife Awareness
Working Alone
Working in and Around Water
Writing for Results

2010 courses delivered
WSBC Supervisory Safety Management
Zoom Boom-Rough Terrain Forklift

Appendix E

SAFETY STRUCTURE FLOWCHART

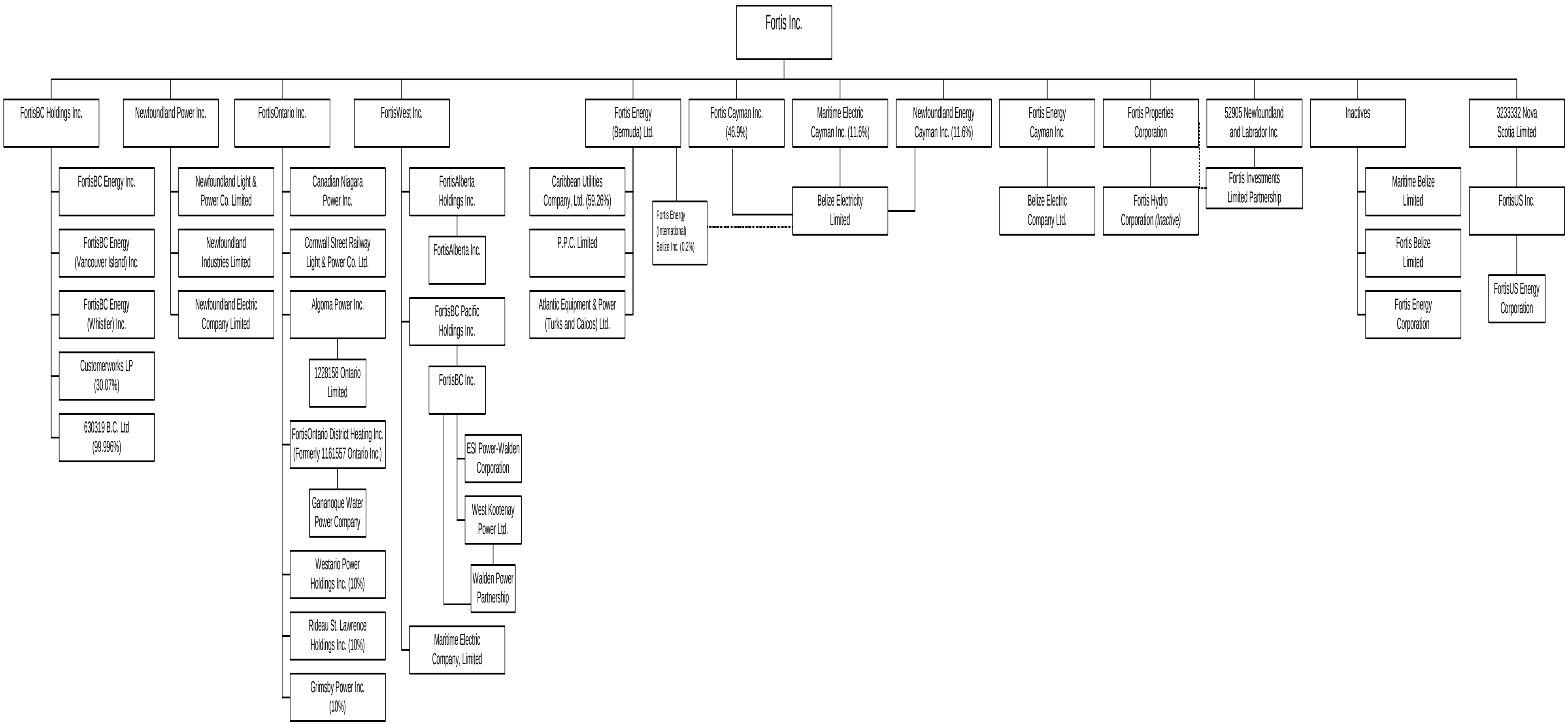
Safety Structure Flowchart



Appendix L

AFFILIATE TRANSACTION REPORT FOR THE YEAR ENDED DECEMBER 31, 2010

A. ORGANIZATIONAL CHART – FORTISBC INC. AND AFFILIATES (EFFECTIVE MARCH 1, 2011)



A. List of Affiliates with Whom FortisBC Transacted Business

The following is a list of all affiliates with whom FortisBC transacted business in the year ending December 31, 2010 including the business address, list of officers and directors as at December 31, 2010 and a description of the Affiliates' business activities.

Fortis Inc.
Suite 1201, 139 Water Street
P.O. Box 8837
St. John's, NL
A1B 3T2

Directors:
David G. Norris (Chair)
Peter E. Case
Frank J. Crothers
Ida J. Goodreau
Douglas J. Haughey
H. Stanley Marshall
John S. McCallum
Harry McWatters
Ronald D. Munkley
Michael A. Pavey
Roy P. Rideout

Officers:

H. Stanley Marshall	*President and CEO*
Barry V. Perry	*Vice President, Finance and CFO*
Ronald W. McCabe	*Vice President, General Counsel and Corporate Secretary*
Donna G. Hynes	*Assistant Secretary*

Description of Business: Fortis Inc. is the largest investor-owned distribution utility in Canada serving approximately 2,100,000 gas and electricity customers. Its regulated holdings include electric distribution utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. Fortis Inc. owns and operates non-regulated generation assets across Canada and in Belize and Upper New York State. It also owns hotels and commercial real estate across Canada.

FortisAlberta Inc.
320 17 Avenue SW
Calgary, AB
T2S 2V1

Directors:	Officers:	
Gregory E. Conn (Chair)	Karl W. Smith	*President & CEO*
Judith J. Athaide	Annette Butt	*Vice President, Human Resources and Corporate Communications*
Brian F. Bietz		
Mary Cameron	Nipa Chakravarti	*Vice President, Customer Service*
William J. Daley	Phonse Delaney	*Vice President, Operations and Engineering*
Al Duerr		
Doug Haughey	Ian G. Lorimer	*Vice President, Finance and CFO*
Joanne R. Lemke	Alan Skiffington	*Vice President, Business Services and Chief Information Officer*
H. Stanley Marshall		
Karl W. Smith	Karl Bomhof	*General Counsel and Corporate Secretary*
John C. Walker		
	Michael G. Olson	*Controller & Treasurer*

Description of Business: FortisAlberta, a wholly owned subsidiary of Fortis Inc., is a distribution utility providing electricity in central and southern Alberta. The Company serves approximately 491,000 customers and met a peak demand of 2,555 megawatts in 2010.

Fortis Pacific Holdings Inc.
25th Floor
700 West Georgia Street
Vancouver, BC
V7Y 1B3

Directors:	**Officers:**	
John C. Walker	John C. Walker	*President and CEO*
David Bennett	Michele Leeners	*Vice President, Finance & CFO*
Michele Leeners	Doyle Sam	*Vice President, Engineering and Operations*
Doyle Sam	David Bennett	*Secretary*

Description of Business: Fortis Pacific Holdings Inc., a wholly owned subsidiary of Fortis Inc., is a British Columbia company that is the parent company of FortisBC Inc.

Newfoundland Power Inc.
55 Kenmount Road
P.O. Box 8910
St. John's, NL
A1B 3P6

Directors:	**Officers:**	
Peggy Bartlett (Chair)	Earl A. Ludlow	*President and CEO*
Frank Davis	Jocelyn H. Perry	*Vice President, Finance & CFO*
Nora Duke	Gary Smith	*Vice President, Customer Operations & Engineering*
Georgina Hedges	Peter S. Alteen	*Vice President, Regulation & Planning*
Earl A. Ludlow		
Edward Murphy		
Fred O'Brien		
Bruce Simmons		
Barry V. Perry		
Jo Mark Zurel		

Description of Business: Newfoundland Power Inc., a wholly owned subsidiary of Fortis Inc., operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves approximately 243,000 customers in the province and met a peak demand of 1,237 MW in 2009.

FortisBC Holdings Inc. (previously Terasen Inc.)
10th Floor
1111 West Georgia Street
Vancouver, BC
V6E 4M3

Directors:	**Officers:**	
H. Stanley Marshall (Chair)	John Walker	*President & CEO*
Harold Calla	David C. Bennett	*Vice President & General Counsel; Corporate Secretary*
Beth D. Campbell		
Brenda Eaton	Roger Dall'Antonia	*Vice President, Finance & Treasurer*
Ida J. Goodreau	Scott A. Thomson	*Executive Vice President, Finance, Regulatory & Energy Supply & CFO*
Roger M. Mayer		
Harry McWatters	Debra G. Nelson	*Assistant Corporate Secretary*
Barry V. Perry		
Linda S. Petch		
David R. Podmore		
John C. Walker		

Description of Business: FortisBC Holdings Inc., a Canadian corporation headquartered in Vancouver, British Columbia, is the parent company of the regulated FortisBC Gas companies. A wholly owned subsidiary of Fortis Inc., FortisBC Holdings Inc., together with its subsidiaries, is one of the largest distributors of natural gas in the greater Pacific Northwest and a leading provider of alternative energy systems.

FortisBC Energy Inc. (previously Terasen Gas Inc.)
10th Floor
1111 West Georgia Street
Vancouver, BC
V6E 4M3

Directors:
H. Stanley Marshall (Chair)
Harold Calla
Beth D. Campbell
Brenda Eaton
Ida J. Goodreau
Roger M. Mayer
Harry McWatters
Barry V. Perry
Linda S. Petch
David R. Podmore
John C. Walker
Beth D. Campbell

Officers:

John C. Walker	*President and CEO*
Dwain A. Bell	*Vice President, Distribution*
David C. Bennett	*Vice President & General Counsel; Corporate Secretary*
Roger Dall'Antonia	*Vice President, Finance and CFO; Treasurer*
Cynthia Des Brisay	*Vice President, Energy Supply & Gas Transmission*
Tom A. Loski	*Vice President, Customer Service*
Robert M. Samels	*Vice President, Business Planning*
Douglas L. Stout	*Vice President, Energy Solutions & External Relations*
Scott A. Thomson	*Executive Vice President, Finance, Regulatory & Energy Supply*
Michael Mulcahy	*Executive Vice President, Customer & Corporate Services*
Debra G. Nelson	*Assistant Corporate Secretary*

Description of Business: FortisBC Energy Inc., is a regulated utility providing natural gas and alternative energy solutions to 96 percent of BC's natural gas customers. The Company services approximately 940,000 customers in 125 communities across British Columbia.

FortisOntario Inc.
1130 Bertie Street
P.O. Box 1218
Fort Erie, ON
L2A 5Y2

Directors:	**Officers:**	
H. Stanley Marshall (Chair)	William J. Daley	*President & CEO*
William J. Daley	Glen King	*Vice President, Finance & CFO*
Earl Ludlow	R. Scott Hawkes	*Vice President, Corporate Services, General Counsel & Corporate Secretary*
Barry V. Perry	Angus S. Orford	*Vice President, Operations*

Description of Business: FortisOntario, a wholly owned subsidiary of Fortis Inc., is an electric transmission and distribution utility, which owns and operates Canadian Niagara Power Inc., Cornwall Electric and Algoma Power. The Company owns regulated transmission assets in the Niagara and Cornwall regions, including an interconnection between New York State and Fort Erie, Ontario. FortisOntario also owns a 10 per cent interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc., and Grimsby Power Inc., three regional electric distribution companies.

Fortis Properties Corp.
Suite 1201, 139 Water Street
P.O. Box 8837
St. John's, NL
A1B 3T2

Directors:	**Officers:**	
H. Stanley Marshall (Chair)	Nora M. Duke	*President & CEO*
Nora M. Duke	Jamie D. Roberts	*Vice President, Finance & CFO*
Barry V. Perry	Terry K. Chaffey	*Vice President, Real Estate*
	Ronald W. McCabe	*Vice President, General Counsel & Corporate Secretary*

Description of Business: Fortis Properties Inc., a wholly owned non-utility subsidiary of Fortis Inc., owns and operates hotels in 8 provinces in Canada and commercial real estate primarily in Atlantic Canada. Its holdings include 21 hotels with more than 4,000 rooms and approximately 2.8 million square feet of commercial real estate.

Walden Power Partnership
Suite 100, 1975 Springfield Road
Kelowna, BC
V1Y 7V7

Description of Business: Walden Power Partnership is the owner of a non-regulated 16 MW run-of-river hydroelectric power plant near Lillooet, BC. The partnership is between FortisBC Inc. and West Kootenay Power Limited.

B. List of Services Agreements

The following is a list of all Services Agreements in effect during the Reporting Period:

a) Shared Services Agreement between FortisBC Inc. and FortisAlberta Inc. dated January 1, 2006; and

b) Mutual Shared Services Agreement – Shared Services between FortisBC Inc. and FortisBC Energy Inc. dated July 1, 2010.

c) Mutual Shared Services Agreement – Shared Services between FortisBC Inc. and FortisBC Holdings Inc. dated July 1, 2010

C. Affiliate Party Transactions Summary

The following is a summary overview for the year ending December 31, 2010, of the transactions provided between FortisBC and its affiliates containing a general description of the transactions and services, the parties involved and the approximate aggregate value.

1. Transactions with **Fortis Inc.**

Transactions charged to Fortis Inc.	
Transaction Type	**Amount ($)**
Labour & Travel Expenses	477,000
2010 Total	477,000

Transactions charged from Fortis Inc.	
Transaction Type	**Amount ($)**
Corporate Governance Expenses	1,283,000
Compensation Recoveries (Non Regulated)	451,000
Pension Recoveries	20,000
Information Technology Services	4,000
2010 Total	1,758,000

2. Transactions with **FortisAlberta Inc.**

Transactions charged to FortisAlberta	
Transaction Type	**Amount ($)**
Pension Related Recoveries	30,000
Board of Directors Expenses	4,000
2010 Total	34,000

Transactions charged from FortisAlberta	
Transaction Type	**Amount ($)**
Metering Services	116,000
Material & Equipment Purchase (Capital)	91,000
Employee Services	50,000
2010 Total	257,000

3. Transactions with **Newfoundland Power Inc.**

Transactions charged to Newfoundland Power	
Transaction Type	**Amount ($)**
Board of Directors Expenses	7,000
2010 Total	7,000

Transactions charged from Newfoundland Power	
Transaction Type	**Amount ($)**
Labour & Travel Expenses	2,000
Share of Conference Board of Canada Subscription	2,000
2010 Total	4,000

4. Transactions with **FortisBC Holdings Inc. (previously Terasen Inc.)**

Transactions charged to FortisBC Holdings Inc. (previously Terasen Inc.)	
Transaction Type	**Amount ($)**
Labour & Travel Expenses	222,000
Internal Audit Services	11,000
Cooperative Safety Program	10,000
Customer Works Ltd. Partnership Board Expenses	5,000
Board of Director Expenses	3,000
Consulting Services	3,000
2010 Total	254,000

Transactions charged from FortisBC Holdings Inc. (previously Terasen Inc.)	
Transaction Type	**Amount ($)**
Board of Director Fees	127,000
Labour & Travel Expenses (Executive Legal)	50,000
Labour & Travel Expenses (Audit Related)	11,000
Insurance Services	5,000
2010 Total	193,000

5. Transactions with **FortisBC Energy Inc. (previously Terasen Gas Inc.)**

Transactions charged to FortisBC Energy Inc. (previously Terasen Gas Inc.)	
Transaction Type	**Amount ($)**
Sale of Power (Tariff Sales)	721,000
Executive Salary	182,000
Labour and Travel Expenses	26,000
Energy Management Program (Joint Watersaver Pilot Program 2010)	14,000
Rebates Paid to Customers	7,000
Meeting Expenses	7,000
2010 Total	957,000

Transactions charged from FortisBC Energy Inc. (previously Terasen Gas Inc.)	
Transaction Type	**Amount ($)**
Rental of Springfield Road Office	247,000
Labour General	60,000
Property Tax Support Services Including Software & License Fees and Travel Expenses	38,000
Employment Programs	33,000
Banquet & Community Award Expenses	16,000
Corporate Report	11,000
Purchase of Natural Gas (Tariff Sales)	11,000
Conference Expenses	3,000
Other misc. expenses	10,000
2010 Total	429,000

6. Transactions with **FortisOntario Inc.**

Transactions charged from Fortis Ontario	
Transaction Type	**Amount ($)**
Board of Directors Expenses	1,000
2010 Total	1,000

7. Transactions with **Fortis Properties Inc.**

Transactions charged from Fortis Properties	
Transaction Type	**Amount ($)**
Canadian Hydropower Dues	5,000
2010 Total	5,000

8. Transactions with **Fortis Pacific Holdings Inc.**

Transactions charged to FPHI	
Transaction Type	**Amount ($)**
O&M and Transfer Pricing Charged to FPHI	6,127,000
Interest Charged to FPHI	13,000
2010 Total	6,140,000

9. Transactions with **Walden Power Partnership**

Transactions charged to Walden	
Transaction Type	**Amount ($)**
O&M and Transfer Pricing Charged to Walden	185,000
2010 Total	185,000

D. Affiliate Party Financial Transactions Summary

The following is a summary of financial transactions provided between FortisBC and its affiliates.

FortisBC Inc. Affiliate Party Financial Transactions January 1, 2010 to December 31, 2010					
Date	Related Party	Terms	Capital Transaction ($000s)	Investing Transactions ($000s)	Financing Transactions ($000s)
28-Feb-10	FPHI	Dividend Payment	(3,500)	-	-
31-May-10	FPHI	Dividend Payment	(3,500)	-	-
31-Aug-10	FPHI	Dividend Payment	(4,000)	-	-
30-Nov-10	FPHI	Dividend Payment	(4,000)	-	-
31-Dec-10	FPHI	Equity Injection	10,000	-	-

Appendix M

Directive 16 and Capitalization Policy

TRANSMISSION AND DISTRIBUTION CAPITAL SUSTAINMENT PROGRAMS

INTRODUCTION AND BACKGROUND

On June 18, 2010 FortisBC filed its 2011 Capital Expenditure Plan, and on December 17, 2010 the Commission issued Order G-195-10, which included in the accompanying Reasons for Decision the following Directive 16:

> *"The Commission Panel directs FortisBC to prepare and file a report detailing a list of Transmission and Distribution Capital Sustaining programs (with the exception of the programs discussed in Section 7.2[1]) each referencing specific sections of the Company's Capitalization Policy guidelines, along with a discussion on the Company's interpretation of why it considers each program to be capital in nature. In addition, the Commission Panel directs FortisBC to include a discussion and analysis on its determination of the $1,000 minimum capitalizable amount, as stated in its current Capitalization Policy, along with a detailed assessment on the justification for this minimum and an assessment of the minimum capitalizable amounts of comparable utilities within British Columbia and other jurisdictions. This report is to be filed to the Commission within 90 days from the date of this Decision."*

On March 1, 2011, the Company requested approval to vary the timing of the report required by Directive 16 to provide that the specified report be filed as part of FortisBC's 2012 - 2013 Revenue Requirements Application (2012-13 RRA). On March 3, 2011 the Company received approval by way of Order G-38-11 to file the report as part of FortisBC's 2012-13 RRA.

Section 2 of this report provides the guidance available under both pre-changeover Canadian Generally Accepted Accounting Principles (CGAAP) and US Generally Accepted Accounting Principles (US GAAP) with regard to distinguishing capital from operating expenditures and accounting for rate regulated activities. Section 3 describes FortisBC's Transmission and Distribution Capital Sustainment Programs and the Company's opinion on

[1] Pursuant to section 7.2 of Order G-195-10, FortisBC classifies as Operating and Maintenance Expense the following programs: Transmission and Distribution Right-of-Way Reclamation, Transmission and Distribution Pine Beetle Kill Hazard Tree Removal, and Distribution Line Hot Tap Connector Replacements.

the capitalization of these expenditures. Lastly, Section 4 provides the Company's minimum threshold for capital expenditures and the results of a survey of other Canadian utilities in this respect.

CAPITALIZE VERSUS EXPENSE UNDER CANADIAN AND US GAAP

Definition of an Asset under Canadian GAAP

The general definition of an asset under CGAAP is provided in the Canadian Institute of Chartered Accountants' (CICA) Handbook Section 1000.29, which defines assets as economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained. An asset has three essential characteristics:

a) it embodies a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows;

b) the entity can control access to the benefit; and

c) the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

In addition, in identifying a benefit, there must be:

a) an ability to earn income or supply a service;

b) a reasonable expectation that the benefit will be provided in future periods; and

c) the future period must be identifiable and greater than one year.

Definition of an Asset under US GAAP

The general definition of an asset under US GAAP is provided in the Financial Accounting Standards Board (FASB) Concept 6, *Elements of Financial Statements*, which defines an asset as probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events. An asset has three essential characteristics (FASB Concept 6.26):

a) it embodies a future benefit that involves a capacity, singly or in combination with other assets, to contribute directly or indirectly to future net cash inflows;

b) a particular entity can obtain the benefit and control others' access to it; and

c) the transaction or other event giving rise to the entity's right to, or control of, the benefit has already occurred.

The kinds of items that qualify as assets are also commonly called economic resources. They are the scarce means that are useful for carrying out economic activities, such as consumption, production, and exchange.

The common characteristic possessed by all assets (economic resources) is "service potential" or "future economic benefit", the scarce capacity to provide services or benefits to the entities that use them. In a business enterprise, that service potential or future economic benefit eventually results in net cash inflows to the enterprise.

Definition of Property Plant and Equipment (PP&E) under Canadian GAAP

Section 3061, *Property, Plant and Equipment*, of the Handbook specifically defines PP&E as identifiable assets that meet all of the following criteria:

a) are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other PP&E;

b) have been acquired, constructed or developed with the intention of being used on a continuing basis; and

c) are not intended for sale in the ordinary course of business.

Definition of PP&E under US GAAP

US GAAP Accounting Standards Codification (ASC or Codification) 360-10, *Property, Plant and Equipment-Overall*, defines PP&E as typically consisting of long-lived tangible assets used to create and distribute an entity's products and services.

Cost of PP&E under Canadian GAAP

Section 3061.05 of the Handbook defines the cost of an item of PP&E as the amount of consideration given up to acquire, construct, develop, or better an item of PP&E and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset.

Section 3061.17 of the Handbook defines the cost of an item of PP&E as including the purchase price and other acquisition costs such as option costs when an option is exercised, brokers' commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges.

Section 3061.20 of the Handbook provides that the cost of an item of PP&E includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity.

Section 3061.23 of the Handbook explains that the cost of an item of PP&E that is acquired, constructed, or developed over time includes carrying costs directly attributable to the acquisition, construction, or development activity (such as interest costs when the enterprise's accounting policy is to capitalize interest costs). For an item of rate-regulated PP&E, the cost includes the directly attributable allowance for funds used during construction allowed by the regulator.

Section 3061.26 of the Handbook states that the cost incurred to enhance the service potential of an item of PP&E is a betterment. Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved.

Cost of PP&E under US GAAP

ASC 360-10 defines the historical cost of acquiring an asset as including the costs necessarily incurred to bring it to the condition and location necessary for its intended use. As indicated in that paragraph, if an asset requires a period of time in which to carry out the activities necessary to bring it to that condition and location, the interest cost incurred during that period as a result of expenditures for the asset is a part of the historical cost of acquiring the asset.

The term activities is to be construed broadly. It encompasses physical construction of the asset. In addition, it includes all the steps required to prepare the asset for its intended use. For example, it includes administrative and technical activities during the pre-construction stage, such as the development of plans or the process of obtaining permits from governmental authorities. It also includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labour disputes, or litigation.

Impact of Status as a Rate Regulated Entity

CGAAP specifically defines rate regulation and acknowledges that assets may arise out of rate regulation. CGAAP also includes a disclosure standard in its body of literature, however industry practice in Canada is to consult US GAAP for further accounting literature related to rate regulation due to its established set of guidelines.

ASC 980-10, *Regulated Operations-Overall*, defines the effects of regulatory accounting.

Regulation of an entity's rates (also referred to as prices) is sometimes based on the entity's costs. Regulators use a variety of mechanisms to estimate a regulated entity's allowable costs, and they allow the entity to charge rates that are intended to produce revenue approximately equal to those allowable costs. Specific costs that are allowable for rate-making purposes result in revenue approximately equal to the costs. The process is a way of setting prices.

Regulators sometimes include costs in allowable costs in a period other than the period in which the costs would be charged to expense by an unregulated entity. For the regulated entity, that procedure can do any of the following:

a) Create assets (future cash inflows that will result from the rate-making process)

b) Reduce assets (reductions of future cash inflows that will result from the rate-making process)

c) Create liabilities (future cash outflows that will result from the rate-making process)

Unless an accounting order indicates the way a cost will be handled for rate-making purposes, it causes no economic effects that would justify deviation from US GAAP applicable to business entities in general. The mere issuance of an accounting order not tied to rate treatment does not change an entity's economic resources or obligations. In other words, the economic effect of regulatory decisions – not the mere existence of regulation – is the pervasive factor that determines the application of US GAAP.

ASC 980-360, *Regulated Operations-Property, Plant and Equipment*, defines allowable costs as all costs for which revenue is intended to provide recovery. Those costs can be actual or estimated.

ASC 980-340, *Regulated Operations-Other Assets and Deferred Costs*, states that actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes;

b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

In some cases, a regulator may permit an entity to include a cost that would be charged to expense by an unregulated entity as an allowable cost over a period of time by amortizing that cost for rate-making purposes, but the regulator does not include the unrecovered amount in the rate base. That procedure does not provide a return on investment during the recovery period. The regulator's action provides reasonable assurance of the existence of an asset. Accordingly, the regulated entity would capitalize the cost and amortize it over the period during which it will be allowed for rate-making purposes. That cost would not be recorded at discounted present value.

FortisBC Interpretation of Canadian and US GAAP Guidance

Based on the accounting guidance above, both Canadian and US GAAP have similar definitions of what constitutes an asset, which is probable future economic benefits obtained or controlled by an entity as a result of past transactions or events. Probable future economic benefits are defined as future cash flows.

PP&E is defined similarly under both Canadian and US GAAP as meeting the definition of an asset and used to create and distribute an entity's products and services. The cost of PP&E includes the costs necessarily incurred to bring an asset to the condition required for its intended use. These costs could include design and engineering, survey costs, site preparation costs, and testing charges. Betterment is the result of enhancing the service potential of an existing item of PP&E, which could be representative of increased output, lower associated operating costs, extended useful life, or improved quality of output.

Both Canadian and US GAAP recognize that assets may arise out of rate regulation. When amounts are excluded from allowable costs for the period, an asset can be created as a result of future cash inflows from future allowable costs that will result from the rate-making process, but only when a regulatory decision has been provided to do so.

FortisBC Capitalization Policy

The Company's Capitalization Policy reflects the principles found in both Canadian and US GAAP.

FortisBC defines Capital Expenditures as expenditures in excess of $1,000 that meet all of the following criteria:

1. Provide substantial benefits for a period of more than one year;
2. Extend the useful life of an asset or increase the capacity of an asset or the quality of output efficiency and may reduce operating costs. An expenditure on a plant item that is recurring in nature or considered routine maintenance is not included; and
3. Are held for use to conduct business/generate income.

CAPITAL SUSTAINMENT AND TREATMENT UNDER CAPITALIZATION POLICY

Transmission Capital Sustainment

I. TRANSMISSION CONDITION ASSESSMENT

The transmission line assessment program is based on an eight-year cycle of inspecting and testing all FortisBC transmission line facilities in order to extend the life of the pole and ensure the integrity of the lines. The programs consist of a test and treat component and an above ground visual condition inspection.

The test and treat component of this work involves drilling test holes for condition testing, addition of pole treatment to reduce internal rot, and occasionally placing pole wrap to reduce surface rot on the pole at ground line. This component of the program is also considered a betterment that typically extends the life of the pole between 8 and 16 years.

The inspection component of this work is a managed, scheduled program designed to ensure all poles and lines are assessed within a reasonable time period based on experience. The inspection work involves engineering activities and various testing charges and is viewed as a betterment by helping to reduce future operating costs and improving quality of output to customers. There are also direct cash flow benefits associated with identifying lines and poles in need of Urgent Repair, of which there is an approved budget available in the capital expenditure plan as discussed below. Failure to identify such items would result in system outages, leaving customers without power and which typically involve higher capital repair costs with significant safety hazards involved. The program also enables the identification, scoping of and budgeting for projects for betterment and life extension through the Transmission Rehabilitation projects in the subsequent year.

The Company is therefore of the opinion that the Transmission Condition Assessment program:

- Provides benefits for a period of more than one year;
- Provides direct cash flow benefits through reduced future operating costs and improved quality of output (i.e. less downtime);
- Aids in the identification, scoping and budget of capital related work completed as part of Transmission Rehabilitation projects or Urgent Repairs (for inspection component);
- Extends the useful life of an asset (for test and treat component);
- Relates to assets that are held for use to conduct business/generate income;
- Should be classified as capital expenditures.

II. TRANSMISSION REHABILITATION

The specific rehabilitation projects for various transmission lines involve expenditures for structural stabilization of the defects identified for rehabilitation in previous years' Condition Assessments. This work may include the installation of a new part that is a betterment to the existing part of the system (e.g. stubbing of poles along a section of line), or may involve the replacement of an existing part where the old part is retired and the new part is added. This work will extend the useful life of the asset and is considered a betterment under the Company's Capitalization Policy.

The Company is therefore of the opinion that the Transmission Rehabilitation program:

- Provides benefits for a period of more than one year;
- Extends the useful life of an asset;
- Relates to assets that are held for use to conduct business/generate income;

- Should be classified as capital expenditures.

III. TRANSMISSION URGENT REPAIR

This work is considered Extraordinary Repairs under the Company's Capitalization Policy. Urgent Repairs normally arise as a result of inspection work performed under the Condition Assessment program or as a result of power outages or other indicators of risk of system default. Before the work can be considered capital it must meet the criteria for capitalization.

These are large significant expenditures relative to the total cost of the asset for major repairs or replacement of existing capital assets that extend their useful life. Minor or ordinary and routine repairs are generally considered operating and maintenance expense.

The Company is therefore of the opinion that the Transmission Urgent Repair program:

- Provides benefits for a period of more than one year;
- Extends the useful life of an asset;
- Relates to assets that are held for use to conduct business/generate income;
- Should be classified as capital expenditures.

Distribution Sustaining Capital

I. DISTRIBUTION CONDITION ASSESSMENT

The distribution line assessment program is based on an eight-year cycle of inspecting and testing all FortisBC distribution line facilities in order to extend the life of the pole and ensure the integrity of the lines. The programs consist of a test and treat component and an above ground visual condition inspection.

The test and treat component of this work involves drilling test holes for condition testing, addition of pole treatment to reduce internal rot, and occasionally placing pole wrap to reduce surface rot on the pole at ground line. This piece of the program is also considered a betterment that typically extends the life of the pole between 8 and 16 years.

The inspection component of this work is a managed, scheduled program designed to ensure all poles and lines are assessed within a reasonable time period based on experience. The inspection work involves engineering activities and various testing charges and is viewed as a betterment by helping to reduce future operating costs and improving quality of output to customers. There are also direct cash flow benefits associated with identifying lines and poles in need of Urgent Repair, of which there is an approved budget available in the capital expenditure plan as discussed below. Failure to identify such items would result in system outages, leaving customers without power and which typically involve higher capital repair costs with significant safety hazards involved. The program also enables the scoping of and budgeting for projects for betterment and life extension through the Distribution Rehabilitation projects in the subsequent year.

The Company is therefore of the opinion that the Distribution Condition Assessment program:

- Provides benefits for a period of more than one year;
- Provides direct cash flow benefits through reduced future operating costs and improved quality of output (i.e. less downtime);
- Aids in the identification, scoping and budget of capital related work completed as part of Distribution Rehabilitation projects or Urgent Repairs (for inspection component);
- Extends the useful life of an asset (for test and treat component);
- Relates to assets that are held for use to conduct business/generate income;
- Should be classified as capital expenditures.

II. DISTRIBUTION REHABILITATION

The specific rehabilitation projects for various distribution lines involve expenditures for structural stabilization of the defects identified for rehabilitation in previous years' Condition Assessments. This work may include the installation of a new part that is a betterment to the old part of the system (e.g. stubbing of poles along a section of line), or may involve the replacement of an existing part where the old part is retired and the new part is added. This work will extend the useful life of the asset and is considered a betterment under the Company's Capitalization Policy.

The Company is therefore of the opinion that the Distribution Rehabilitation program:

- Provides benefits for a period of more than one year;
- Extends the useful life of an asset;
- Relates to assets that are held for use to conduct business/generate income;
- Should be classified as capital expenditures.

III. DISTRIBUTION REBUILDS

This work involves the replacement of aged and/or deteriorated capital equipment or the addition of capital assets to the system. Items include rebuilding failing overhead and underground conductor and include replacing rotted poles and platforms, replacing leaking transformers and installing ground grids at ungrounded services and the retirement of old plant.

Replacement of a capital asset is considered an improvement that will extend the life and should be capitalized under the Company's Capitalization Policy.

The Company is therefore of the opinion that the Distribution Rebuilds:

- Provides benefits for a period of more than one year;
- Extends the useful life of an asset;
- Relates to assets that are held for use to conduct business/generate income;
- Should be classified as capital expenditures.

IV. DISTRIBUTION SMALL PLANNED CAPITAL

This program is similar to the Distribution Condition Assessment and Rehabilitation programs but captures off-cycle work required to keep the distribution lines safe and reliable. Each year operational and safety concerns on the distribution system including storm damage, clearance problems and aging equipment and the retirement of old plant, are identified by field staff outside of the normal assessment cycle.

The Company is therefore of the opinion that the Distribution Small Planned Capital:

- Provides benefits for a period of more than one year;
- Extends the useful life of an asset;
- Relates to assets that are held for use to conduct business/generate income;
- Should be classified as capital expenditures.

V. FORCED UPGRADES AND LINE MOVES

This program is required to complete distribution upgrades driven by third party requests. These include relocation of distribution lines due to highway/road widening or improvements that are initiated by the BC Ministry of Transportation and/or municipalities, as well as miscellaneous customer line move requests where FortisBC does not have sufficient land rights for the facilities located on customer property. These types of expenditures involve the construction of new facilities and the retirement of existing facilities and meet the criteria to be classified as a capital expenditure.

The Company is therefore of the opinion that the Forced Upgrades and Line Moves:

- Provides benefits for a period of more than one year;
- Extends the useful life of an asset;
- Relates to assets that are held for use to conduct business/generate income;
- Should be classified as capital expenditures.

VI. DISTRIBUTION URGENT REPAIR

This work is considered Extraordinary Repairs under the Company's Capitalization Policy. Urgent Repairs normally arise as a result of inspection work performed under the Condition Assessment program or as a result of power outages or other indicators of risk of system default. Before the work can be considered capital it must meet the criteria for capitalization.

These are large significant expenditures relative to the total cost of the asset for major repairs or replacement of existing capital assets that extend their useful life. Minor or ordinary and routine repairs are generally considered operating and maintenance expense.

The Company is therefore of the opinion that the Distribution Urgent Repairs:

- Provides benefits for a period of more than one year;
- Extends the useful life of an asset;
- Relates to assets that are held for use to conduct business/generate income;
- Should be classified as capital expenditures.

MINIMUM THRESHOLD FOR CAPITAL EXPENDITURES OF $1,000

i. Determination of the Minimum Threshold

FortisBC bases its $1,000 minimum threshold for Capital Expenditures on "The Minimum rule" of the BCUC Uniform System of Accounts Prescribed for Electric Utilities (section 7). The published minimum in 1980 was set at $500. Inflated to January 1, 2007 dollars using the Handy Whitman Cost Trends of Electric Utility Construction for the Pacific Region would make the minimum approximately $775 (or $940 as of July 1, 2010). The Company has rounded the amount to $1,000 for administrative ease.

ii. Comparison with other Utilities

The Company conducted an informal survey of eight utilities in British Columbia and other Canadian jurisdictions regarding the minimum amounts for capitalization. As certain of the utilities requested that the information be held in confidence, the following summary is provided.

- Utility A has no minimum amount set for capital expenditures.
- Utility B has no dollar threshold for capitalization.
- As a practical matter in Utility C, items of a capital nature less than $500 are expensed as incurred.
- Utility D expenditures must meet a minimum capitalization level of $500.
- Utility E expenditures must meet a minimum capitalization level of $500.
- Utility F's policy is to capitalize all costs of new assets constructed or purchased. The exception to this is that units of property costing less than $1,000 that are not part of a project are to be charged to operating expense. Examples include: tools and equipment, supplies, hardware and software, cell phones.
- Utlity G expenditures must meet a minimum capitalization level of $1,000.
- Utlity H has stated that in general, their policy is that Items costing less than $5,000 are not capitalized.

Therefore, FortisBC appears to be in line with the selected utilities sourced in the informal survey based on the distribution in range of minimum capitalized amounts from $0 to $5,000 as follows:

Capitalization Minimum Threshold	Number of Utilities
No minimum capitalization threshold	2
Minimum capitalization level of $500	3
Minimum capitalization level of $1,000	2
Minimum capitalization level of $5,000	1

CONCLUSION

The Company is of the opinion that it has established a Capitalization Policy that is consistent with the principles of both Canadian and US GAAP. The Company also understands that policy requires interpretation but it is confident that it has applied the Capitalization Policy in a manner that is appropriate and in the best interests of its Customers.

Appendix N

CAPITAL EXPENDITURE VARIANCES

CAPITAL EXPENDITURE VARIANCES

Annual variances of actual from forecast expenditures can arise from multiple factors, including the timing of construction, market prices and economic conditions at the time of project execution, as well as the accuracy of estimating used to forecast the expected capital expenditures required.

In its Reasons for Decision accompanying Order G-195-10 concerning the Company's 2011 Capital Expenditure Plan, the Commission Panel directed "FortisBC to provide information, in its next revenue requirements application, on how it plans to narrow the variance between approved and actual capital expenditures to ensure that rates charged to customers and the return received by shareholders are both fair and equitable". FortisBC provides the following discussion in response to the above directive.

The Company forecasts capital expenditures based on the best available estimates at the time of filing an application for approval. Typically, forecast capital expenditures are based on actual labour and material inputs realized by FortisBC for similar work previously performed. As part of each Revenue Requirements application, these forecast capital expenditures are updated to reflect any changes resulting from more detailed project information, as well as any changes in pricing and/or required labour to complete the project. Generally, as the level of project definition increases, the available information on which to base an estimate of forecast expenditures is also enhanced, which may result in a change to forecast capital expenditures at the time of the update.

Table 1 below details the variance between actual and forecast capital expenditures by year. The factors impacting these variances are discussed in further detail below.

Table 1 Capital Expenditure Variances by Year

	2006A	2007A	2008A	2009A	2010A	2011F	Average
Actual/Forecast	109,348	143,742	111,579	112,723	142,038	92,025	
Decision	104,913	133,660	124,937	129,466	167,417	95,718	
Variance	4,435	10,082	(13,358)	(16,743)	(25,379)	(3,693)	(7,443)

Note: Above amounts exclude expenditures related to demand side management and cost of removal

Approvals and Permitting

During the period of 2006 to 2010, the Company engineered and constructed eight greenfield substations across its service territory. Each of these substation projects required a variety of provincial, regional and municipal permits and approvals, in addition to the required approval for applications under sections 44.2 and/or 45 of the Utilities Commission Act. Acquisition of these approvals and permits, in many cases, involved public processes and in some instances multiple public processes for a single project. The timing and progress of the approval processes is largely determined by the agency or department involved in the process, and for the most part is beyond the control of the Company. The following are examples of project delays resulting from approval and permitting processes required for project execution:

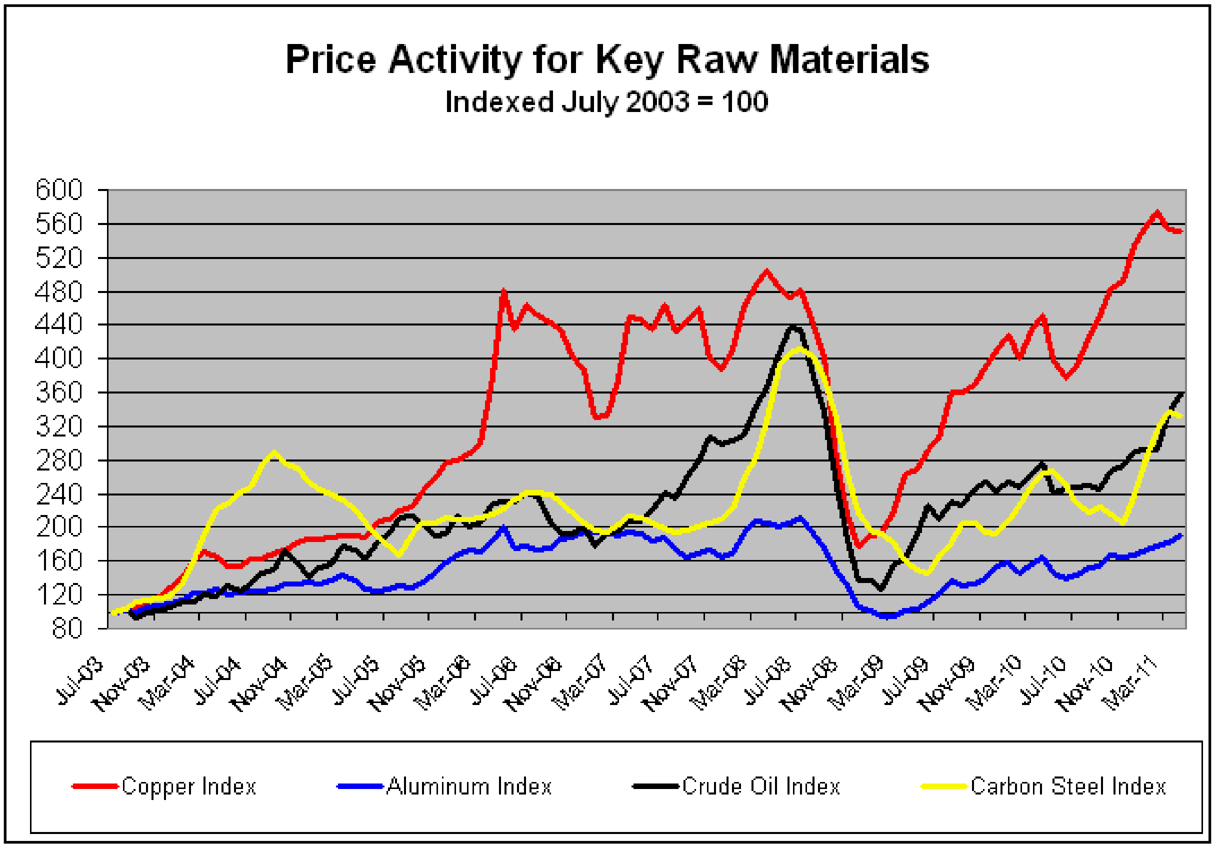
- Kettle Valley Distribution Source Project – change in preferred line route required due to additional approvals required to obtain rights-of-way from Ministry of Transportation, including a request to complete geotechnical studies for a portion of the route;
- Naramata Substation Project – project approvals and permitting delayed for public input and site relocation;
- Ellison Substation – project approvals and permitting, and municipal rezoning delays; and
- Black Mountain Substation – municipal rezoning delay.

The approval and permitting delays identified above are largely typical of greenfield construction, and in many instances are unavoidable. These delays are consistent with the experiences of other utilities in British Columbia and Canada with respect to greenfield projects, due to rapidly changing stakeholder expectations. However, in the instance of two recently constructed substations, Benvoulin and Ootischenia, the Company was successful in completing the projects within one month of the forecast completion date. In the case of the construction of the Benvoulin substation, the approval to remove the preferred site from the Agricultural Land Reserve (ALR) as well as the receipt of approval for rezoning from the City of Kelowna was achieved approximately six months ahead of the forecast date. The completion of these project elements ahead of schedule is due in part to the thorough customer consultation and review process of potential sites undertaken by the Company during development of the CPCN application, and the fact that a suitable location that met the needs of the Company and stakeholders existed. In this case, the preferred substation site was publicly supported as a suitable location for construction of a greenfield substation. In addition, FortisBC successfully completed an agreement with the Westbank First Nations early in the project schedule to use lands on the south side of Mission Creek for the distribution duct bank as well as a staging area for drilling under the creek bed. FortisBC's close working relationship with its First Nations stakeholders allowed the Company to negotiate a successful agreement critical to project completion in a relatively short amount of time.

FortisBC does perform an analysis of the risk of delay to the components of a project which is reflected in the recommended solution provided as part of the application to the Commission for project approval. Despite conducting such an analysis, the issues associated with greenfield site selection have, for some projects, resulted in additional delays related to public input as well as municipal approval for rezoning. To mitigate this, FortisBC's strategy has been to develop, and continue to develop, an extensive public consultation process to identify and address stakeholder concerns early in the project definition and development process. In the case of the Benvoulin Substation project, this strategy resulted in the identification of a suitable site with the support of all involved stakeholders. This support helped to ensure municipal approval of the required rezoning well ahead of the forecast schedule, which also contributed to the project being successfully completed on time and under budget. Despite this strategy, it is still expected that there will be instances where unavoidable project delays related to approvals and/or permitting exist, however the Company does not anticipate delays of the same extent related to approval and permitting as no new greenfield projects are currently anticipated within the Company's five year planning horizon.

Market Prices and Economic Conditions

Project estimation and expenditures during the 2006 – 2010 timeframe were subject to dramatic changes in economic and market conditions, which were reflected in commodity and labour market prices. In some instances, these changing conditions resulted in extended lead times for major equipment purchases. Commodity prices beginning in mid-2006 increased substantially through 2008, before declining and eventually stabilizing (with the exception of copper) during 2009 and 2010. Since then, pricing for commodities used in utilities systems construction has been trending upwards, as displayed in the chart below. This dramatic volatility in commodity pricing was well beyond normal price volatility that occurs in utility construction.



The labour market for contract labour/engineering resources also tightened during the 2006-2008 period. Escalations in external construction labour pricing through this period contributed to variances for some project construction costs. As noted in the Spring 2008 MMK Report, weekly wage earnings in utilities system construction increased by more than 25 percent during the period between the third quarter of 2006 and the fourth quarter of 2007, reflecting the escalated market conditions for utility system construction labour. By 2009, as noted in the Spring 2010 MMK Report, the upward movement in electric utility price indices began to subside, with both the Distributions Systems and Transmission System price index declining 0.3 per cent. As well, escalations in labour pricing were reduced in 2009 and early 2010 from the annual increases experienced in previous years.

In addition to cost escalation for labour and engineering resources, the tight market conditions also contributed to longer equipment delivery times, resulting in project delays in certain instances.

Examples of capital project cost and timing affected by market conditions include:

- Okanagan Transmission Reinforcement Project - estimated and approved during highest of market prices, savings of $32.5 million currently forecast as prices eased;
- Benvoulin Substation and other transmission and distribution projects benefited from lower prices;
- Kettle Valley Substation – cost of transformer increased from estimate due to market escalation in commodities, as well transformer delivery delayed due to market conditions
- South Slocan Unit 1 Life Extension - rescheduled from 2007 to 2009 due to extended delivery time for turbine

To address the issue of variances between the level of approved and actual capital expenditures, the Company uses a strategy that includes using a competitive tender process for equipment and labour where possible to achieve the most economical pricing, as well as the use of optional completion dates for non-critical project components to help obtain competitive pricing. Going forward, FortisBC does not anticipate the same degree of variance in cost or timing as a result of market conditions, in part due to the fact that the Company is not forecasting capital expenditures involving items with long lead times for delivery, and also due in part to the fact that market pricing and delivery times appear to have stabilized from the escalated levels seen in 2007-2008.

Where items with long lead times for delivery are required for a project, the contractual relationship between the Company and the vendor/manufacturers is structured to ensure that FortisBC ratepayers are protected in the event of delay in materials delivery. Despite this, the Company is cognizant of the ripple effect delivery delays can have on a project, both in terms of resource availability as well as operational timing (outage requirements, for example). FortisBC continually strives to avoid project delays wherever possible, and mitigate the effect of such delays (should they occur) through the use of schedule and/or performance penalties (for vendors/contractors) as well as alternative project component staging.

Accuracy of Estimation

FortisBC continues its efforts to improve the accuracy of its capital expenditure estimates. In the 2012 -2013 Capital Expenditure Plan, expenditure estimates have been prepared consistent with the recommended practices of the Association for the Advancement of Cost Engineering (AACE). Specifically, the target level of estimation for projects within the two-year period is, where possible, a Class 3 (Definition Phase) level of accuracy. Section 2.2 of the Company's 2012 Integrated System Plan (Volume 1) describes its approach to project estimation.

In certain expenditure areas such as Capital Sustainment, an increased focus on development of an Asset Management strategy is expected to result, over time, in improved expenditure forecasts, based on equipment condition assessment. This will lead to an optimized maintenance program, and assist in forecasting a prudent level of Capital Sustainment activity.

Summary

In the long run, customer rates and shareholder returns are determined based on Plant in Service, which includes all prudently incurred capital costs. In the short term, capital expenditures are excluded from rate base until assets under construction are completed and in service. The Company updates its capital expenditure forecasts, to the best of its ability, at the time of each Revenue Requirements. .

FortisBC continues to develop and refine its processes for capital project definition and development to ensure that the information included as part of a project application is complete in all regards, and provides sufficient certainty for the Commission and stakeholders around the estimated costs and timing of the project. The Company acknowledges the issue of capital expenditure variances as displayed in Table 1 above, and the importance of the concerns that such variances may prompt from the Commission, stakeholders, and rate payers at large. Despite these variances, FortisBC also recognizes that through prudent cost management, the Company has successfully executed annual capital budgets within reasonable time and cost variances. Given the unforeseen and dramatic volatility in labour, and in particular commodity pricing, combined with the fact that many of the capital projects executed by FortisBC over the previous five years have involved greenfield construction, the Company remains of the opinion that its history of forecasting capital expenditures demonstrates sufficient rigour in the forecasting process despite the challenges experienced in the past number of years as noted above.

Although variances between approved and actual capital expenditures are still likely to occur in some instances, it is FortisBC's expectation that going forward, the continued development of the strategies and processes discussed in this document will allow the Company to mitigate the level of variances in capital expenditures as compared to previous years, and continue to deliver safe and reliable electric service to its customers.